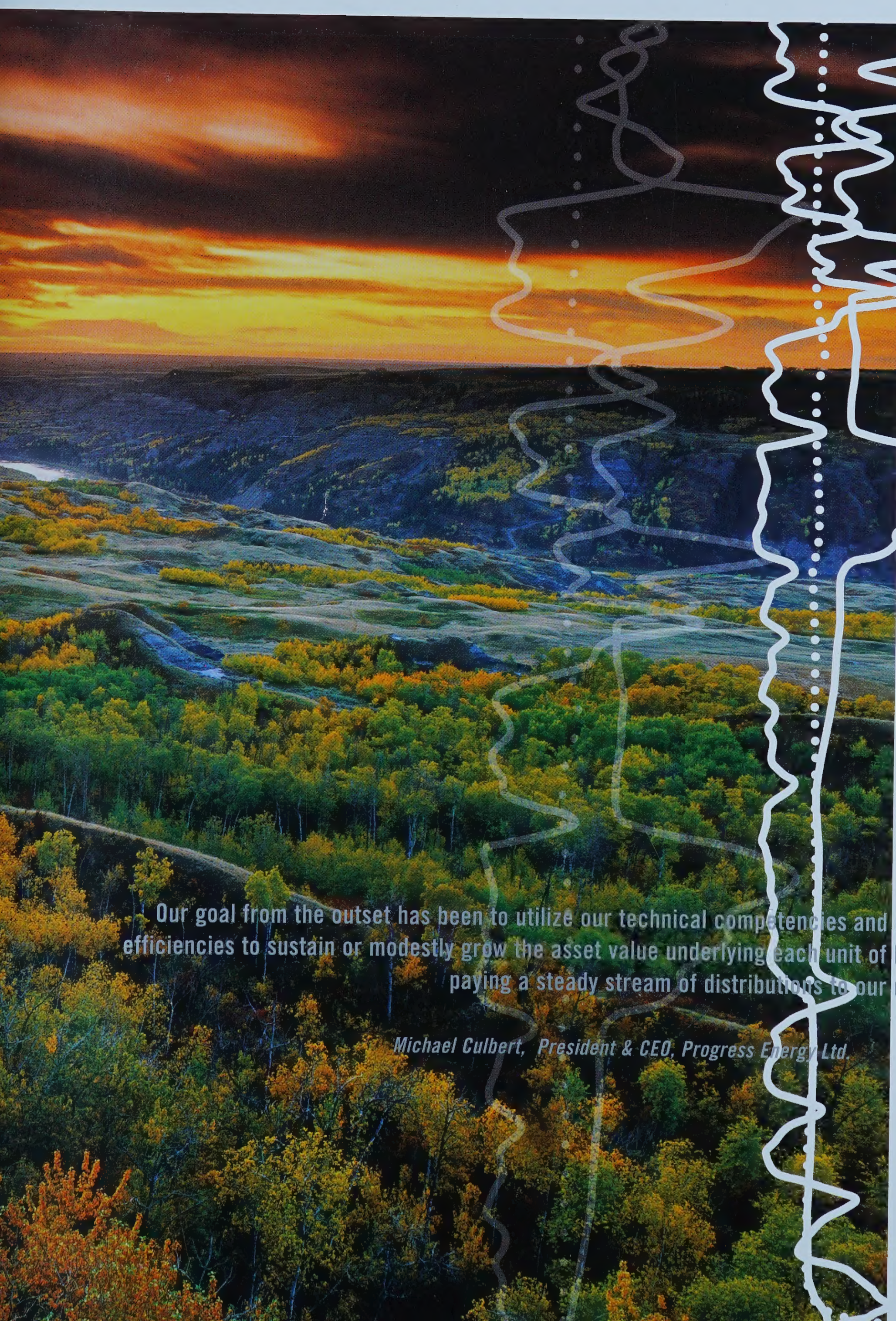
Progress Energy Trust Corporate Profile

Sustainable Performance



Our goal from the outset has been to utilize our technical competencies and capital investment efficiencies to sustain or modestly grow the asset value underlying each unit of Progress Energy Trust while paying a steady stream of distributions to our unitholders

Michael Culbert, President & CEO, Progress Energy Ltd.

PROGRESS ENERGY

Progress Energy's assets are characterized by four distinct operating regions: Deep Basin; central Alberta; Fort St. John Plains and Foothills.

The primary focus is in two of Western Canada's premier natural gas growth regions; the Deep Basin of northwest Alberta and the Foothills of northeast British Columbia.

Each of the Company's operating regions contains large contiguous undeveloped land holdings, high working-interest properties and operatorship of its major properties. The Trust utilizes its technical competencies to sustain or modestly grow reserves and production while generating industry leading capital and operating efficiencies.

The Deep Basin and Foothills continue to grow through crown land sales, asset acquisitions and farm-ins on industry competitors.

Deep Basin
Total acreage:
2007 average producti
2007 wells drilled:
Key properties:
• Gold Creek • Wapiti
• Elmworth • Copton

Foothills
Total acreage:
2007 average producti
2007 wells drilled:
Key properties:
• Town • Bubble
• West Beg • Sasqu

Fort St. John Plains
Total acreage:
2007 average producti
2007 wells drilled:
Key properties:
• Stoddart • Two Ri
• Currant

Central Alberta
Total acreage:
2007 average producti
2007 wells drilled:
Key properties:
• Gilby • Prevo

281,165
/d): 12,194
32 (22.5 net)

• Karr
• Ojay

172,345
/d): 5,814
49 (16.9 net)

• Julienne
• Tommy South

72,360
/d): 1,993
2 (1.2 net)

• West Eagle

20,353
/d): 1,840
9 (7.0 net)

•Thorsby

NORTHEAST BRITISH COLUMBIA FOOTHILLS

Julienne
Pushing exploration westward, Julienne produces from the Cretaceous horizons and continues to expand through-on trend drilling. Production can be quickly tied-in through Progress owned area infrastructure.

Bubbles
Acquired in early 2007, Bubbles produces primarily from the Halfway and Slave Point formations. It contains a substantial inventory of on-trend Halfway drilling opportunities and re-completions.

Town
A legacy a… certain Town we… been producin… over 30 years. Th… 00% Progress propert… ides a stable base of … uction and infrastr… re from which to furth… evelop area lands.

NORTHWEST ALBERTA DEEP BASIN

Wapiti
Acquired late in the second quarter, Wapiti provides a deep inventory of drilling opportunities in the same producing horizons as Gold Creek. The area also has well developed infrastructure.

Gold Creek
Gold Creek represents the Company's largest producing area which is characterized by its multiplicity of producing zones at depths up to 2,500 meters. Ownership in well developed infrastructure ensures that wells are tied-in immediately.

Copton-Lynx
Copton-Lynx provides exposure to higher impact exploration and development, largely targeting shoreface sandstones along the southern edge of the Deep Basin.

Progress Energy Trust was formed in July 2004 through the amalgamation of two high growth junior exploration and production companies. Progress targets sustainable production and reserves per unit through the utilization of its technical capability and capital investment efficiencies.

Primary regions of operation include the Deep Basin of northwest Alberta and the Foothills of northeast British Columbia. In these regions, Progress is able to capitalize on its technical strengths in multi-zone, tight gas exploration and development.

Julienne
Pushing exploration westward, Julienne produces from the Cretaceous horizons and continues to expand through-on trend drilling. Production can be quickly tied-in through Progress owned area infrastructure.

Bubbles
Acquired in early 2007, Bubbles produces primarily from the Halfway and Slave Point formations. It contains a substantial inventory of on-trend Halfway drilling opportunities and re-completions.

Town
A legacy asset, certain Town wells have been producing for over 30 years. This 100% Progress property provides a stable base of production and infrastructure from which to further develop area lands.

Copton-Lynx
Copton-Lynx provides exposure to higher impact exploration and development, largely targeting shoreface sandstones along the southern edge of the Deep Basin.

Progress Energy Trust

Sustainable Performance

Annual Report to Unitholders 2007

To our Unitholders,

As we entered 2007, we knew that Progress Energy would be faced with challenges but anticipated that opportunities may also arise. During 2007, investor confidence was shaken by the trust taxation announcement, lower natural gas prices and world wide capital market pressures. During these times of market uncertainty and natural gas price weakness Progress was well positioned and capitalized by making two strategic acquisitions. These acquisitions have strengthened our asset base within our core operating regions and have expanded our opportunity inventory substantially, placing us in an enviable position to sustain our performance for years to come.

Sustainability, to us, has always been measured by our ability to maintain or modestly grow the reserves, production and net asset value underlying each unit of the trust over the longer term. By applying our industry leading capital efficiencies and low cost structure, we continue to grow the underlying value of the Company. Historically, we have achieved asset value sustainability and growth through internally generated drilling opportunities but we have always believed that if we were patient, the right acquisition opportunity would present itself. In 2007, we invested $428 million to acquire assets from two major international producers. These assets were focused exclusively in our existing regions of operation in the Deep Basin at Wapiti, Copton/Lynx and Ojay and in the Foothills of northeast British Columbia at Bubbles, Tommy and Green. Given our successful exploration and exploitation track record in the Deep Basin and Foothills, we believe these assets represent a tremendous opportunity to apply our knowledge and understanding of the regional geology along with our capital efficiencies to create even further value for our unitholders.

As we move through the four year trust transition period, Progress is positioning itself for the post 2010 era. We believe that continuing to return a portion of our cash flow to our unitholders, or shareholders, will remain desirable. We will further build upon our asset base and increase our inventory of drilling opportunities. One aspect of our preparation that has not received much consideration is the large tax pool balance we have amassed. We ended 2007 with $1.2 billion in tax pools with the majority comprising 100 percent deductible exploration expenses. These tax pools provide substantial sheltering of income well beyond 2010 when the taxation of trusts occurs.

Operational Results

Turning to our 2007 year-end results, our drilling program replaced 165 percent of production on a proved plus probable basis at a finding and development (F&D) cost of $9.91 per boe, excluding changes in future development capital and $14.59 per boe, including changes in future development capital. Our operating netback was $29.11 per boe in 2007 which generates a recycle ratio of two times. With the drilling program and acquisitions included we replaced 361 percent of production on a proved plus probable basis and accomplished this at a finding, development and acquisition (FD&A) cost of $14.50 per boe, excluding changes in future development capital. Including changes in future development capital, the FD&A cost was $16.67 per boe. Our reserve base grew by 34 percent to 86.8 million boe from 64.9 million boe while our reserve life index remained constant at approximately 10 years.

In 2007 we participated in 48 net wells, with a 95 percent success rate. The drilling program was primarily focused on the Deep Basin and Foothills regions where we continue to expand our drilling inventory and land base. We began the year with approximately 363,000 net undeveloped acres in our land portfolio and grew this by over 50 percent to 545,000 net undeveloped acres through a series of acquisitions, crown land sales and farm-ins.

The focus going forward will be on the continued exploration and development of the Deep Basin and the Foothills regions because they fit our competencies in multi-zone, tight gas development. The Deep Basin represents approximately 45 percent of our asset base and remains a highly desirable area because of the multiplicity of producing horizons and the well developed infrastructure. Our growth driver is the Foothills region of northeast British Columbia where we and our working interest partner, ProEx Energy Ltd., continue to expand this long life, tight gas, multi-zone resource region.

Financial Results

Financially in 2007, we generated cash flow from operations of $214.3 million, or $2.02 unit, and made distributions of $114.1 million, or $1.20 per unit, for a basic payout ratio of 53 percent, or 61 percent including the impact of the exchangeable shares. Net capital investment in 2007 was $566.4 million and we ended the year with total debt (comprising the working capital deficit, outstanding bank debt and unsecured convertible debentures) to 2007 cash flow of 2.1 times. We will continue to pursue our target range of between 1.5 and 2.0 times by building our balance sheet as commodity prices strengthen. We currently have a $375 million credit facility of which $78.4 million was undrawn as at December 31, 2007.

Alberta New Royalty Framework

In October 2007, the provincial government of Alberta announced changes to the royalties payable by energy companies exploring and producing in Alberta which are to take effect in 2009. Since this time we have been working with others in industry to ensure that our projects continue to be economic. The government has acknowledged that they will work with stakeholders to address "unintended consequences" before the 2009 implementation. These efforts have been delayed as a result of the March 3, 2008 Alberta provincial election. Based on our interpretation of details provided to date these proposed changes could reduce our cash flow by approximately five percent in 2009 based on a realized natural gas price of $7.00 per gigajoule. We will continue to maintain an open dialogue with the provincial government as we move closer to the implementation date. Approximately 60 percent of Progress' production is from Alberta with the remainder predominantly from British Columbia so depending on the outcome of the final regulations we have investment choices.

Canadian Federal Budget

As we move toward 2011, we will benefit from the recently announced combined federal and provincial proposed tax rate reductions from the current level of 31.5 percent to 25 percent in 2012, the lowest expected corporate rate in Canada.

Commodity Environment

On the commodity front, we are seeing positive changes in the supply-demand balance for natural gas. Although natural gas production in North America has shown minor growth, it requires an accelerating pace of drilling in order to offset annual depletion, yet natural gas focused rig activity has been stagnant for the past year. LNG supply grew in 2007 and had a negative impact on North American natural gas prices. The growth in supply was largely the result of a lack of weather related demand in Europe through winter and spring. These LNG cargoes were then diverted to higher netback markets in the U.S. thereby filling storage to record levels. On the demand side, weather will continue to be a key factor in consumption patterns for residential and commercial heating load in winter and electric power generation for air conditioning load in the summer. We continue to hedge our production to provide certainty to a portion of our revenue stream. Currently we have hedged approximately 50 percent of our production for the upcoming summer season and we are establishing targets for the 2008 and 2009 winter period.

Outlook

As we step into 2008, we maintain our keen focus on building underlying value through the drill bit and through selective acquisitions as we demonstrated in 2007. Strengthening our already dominant position in core operating regions remains paramount and we believe that 2008 may create opportunities to further enhance our asset base. We are targeting average production of approximately 23,500 boe per day which includes the scheduled 22-day plant turnaround at the Spectra-owned McMahon gas processing facility in northeast British Columbia.

Our capital investment program for 2008 has been set at a range of $110 to $125 million and we anticipate drilling approximately 50 net wells. Our distribution has been set for the first quarter at $0.10 per trust unit per month. At this level of distribution we expect to maintain our payout ratio within our historic range of 50 to 60 percent. The level of distributions and planned 2008 capital investment program reinforce our commitment to sustainability and position us to take advantage of opportunities that may arise in the current market.

On behalf of the management team at Progress, we would like to thank our dedicated employees for once again delivering strong results. Our management team will change in 2008 with the retirement of Neil Samis, Vice President Production, and we thank him for his dedication and assistance in building our Company and wish him all the best in his retirement. Gary Miller has been promoted to Vice President Operations and James Stannard has been promoted to Vice President Engineering.

To our Board, we extend our appreciation for their insights and continued support as we work together to increase the value of every unit of Progress Energy Trust.

Sincerely,

(signed) *"Michael R. Culbert"*

President and Chief Executive Officer

Progress Energy Trust

Reserve Summary

RESERVES

Progress Energy Trust's ("Progress" or the "Trust") reserves were prepared by the independent engineering firm of GLJ Petroleum Consultants ("GLJ") in 2007, as well as prior years back to 2001. Reserves included herein are stated on a company interest basis (before royalty burdens and including royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument ("NI") 51-101. The Trust's actual natural gas and petroleum reserves and future production will be greater than or less than the estimates provided. The estimated future net revenue from the production of the Trust's natural gas and petroleum reserves does not represent the fair market value of the Trust's reserves. In addition to the information disclosed in this annual report, more detailed information on a net interest basis (after royalty burdens and including royalty interests) and on a gross interest basis (before royalty burdens and excluding royalty interests) is included in the Trust's Annual Information Form.

- Total proved reserves at December 31, 2007 increased 28 percent to 61.7 million boe compared to 48.2 million boe in 2006.
- Total proved plus probable reserves at December 31, 2007 increased 34 percent to 86.8 million boe compared to 64.9 million boe in 2006.
- Reserve growth in 2007 was achieved through a corporate acquisition completed April 2, 2007 with assets in the Deep Basin and Foothills regions, an asset acquisition in the Wapiti area of the Deep Basin completed May 31, 2007, as well as through the drill bit. As a result, Progress replaced 361 percent of production on a proved plus probable basis and 261 percent on a proved basis.

2007 SUMMARY OF OIL AND GAS RESERVES
Forecast Prices and Costs
Company Interest

	Light and Medium Crude Oil	Natural Gas Liquids	Natural Gas	Total 2007	Total 2006
	(mbbls)	(mbbls)	(bcf)	(mboe)	(mboe)
Proved					
Developed producing	4,241	3,348	249.4	**49,149**	41,274
Developed non-producing	193	434	30.7	**5,745**	3,776
Undeveloped	108	448	37.7	**6,842**	3,171
Total proved	4,542	4,230	317.8	**61,736**	48,221
Probable	1,402	1,606	132.4	**25,082**	16,662
Total proved plus probable	5,944	5,837	450.2	**86,818**	64,883

Note: May not add due to rounding

Forecast Prices and Costs
Net Present Value of Reserves After Income Taxes

($ millions)	Undiscounted	Discounted at 5%	Discounted at 8%	Discounted at 10%
Proved				
Developed producing	1,404	1,075	950	884
Developed non-producing	151	116	102	94
Undeveloped	138	97	81	72
Total proved	1,692	1,288	1,133	1,051
Probable	642	383	304	265
Total proved plus probable	2,335	1,671	1,436	1,316

Note: May not add due to rounding

Forecast Prices and Costs
Price Assumptions

The January 1, 2008 pricing forecasts presented below have been prepared by GLJ. These prices have been utilized in determining the reserves and cash flow forecasts.

Year	Crude Oil WTI	Crude Oil Edmonton Light	Natural Gas AECO	Natural Gas Sumas Spot
	($US/bbl)	($Cdn/bbl)	($Cdn/MMBtu)	($US/MMBtu)
2008	92.00	91.10	6.75	6.90
2009	88.00	87.10	7.55	7.70
2010	84.00	83.10	7.60	7.70
2011	82.00	81.10	7.60	7.70
2012	82.00	81.10	7.60	7.70
2013 – 2017[1]	82.34	81.44	7.96	8.06
Thereafter (%/year)[2]	+2.0	+2.0	+2.0	+2.0

[1] Prices shown are an average over the period.
[2] Percentage change of 2.0% represents the change in future prices each year after 2017 to the end of the reserve life.

2007 RESERVE RECONCILIATION
Forecast Prices and Costs
Reconciliation of Company Interest Reserves by Principal Product Type

	Light and Medium Crude	Natural Gas	Natural Gas Liquids	Total
Proved Producing	(mbbl)	(bcf)	(mbbl)	(mmboe)
Opening balance	4,672	200.12	3,248	41.3
Exploration discoveries	-	0.08	3	-
Drilling extensions, improved recovery and infill drilling	5	37.27	557	6.8
Technical revisions	211	(20.34)	(439)	(3.6)
Acquisitions	138	74.86	506	13.1
Dispositions	-	(0.06)	-	-
Production	(784)	(42.57)	(528)	(8.4)
Closing Balance	4,241	249.36	3,348	49.1
Total Proved				
Opening balance	4,942	236.91	3,794	48.2
Exploration discoveries	-	0.08	3	-
Drilling extensions, improved recovery and infill drilling	5	70.83	944	12.8
Technical revisions	242	(23.23)	(496)	(4.1)
Acquisitions	138	75.82	513	13.3
Dispositions	-	(0.06)	-	-
Production	(784)	(42.57)	(528)	(8.4)
Closing Balance	4,542	317.78	4,230	61.7
Proved Plus Probable				
Opening balance	6,341	321.13	5,021	64.9
Exploration discoveries	-	0.09	4	-
Drilling extensions, improved recovery and infill drilling	7	110.46	1,408	19.8
Technical revisions	211	(32.82)	(693)	(5.9)
Acquisitions	169	94.00	626	16.5
Dispositions	-	(0.07)	-	-
Production	(784)	(42.57)	(528)	(8.4)
Closing Balance	5,944	450.22	5,837	86.8

Note: May not add due to rounding

Reserve Additions and Revisions

Reserve additions were booked generally in line with the Trust's activities in the operating regions in 2007. Exploration and development and acquisitions resulted in the largest reserve additions at Gold Creek, Copton/Lynx and Wapiti in the Deep Basin region of northwest Alberta and at Bubbles in the Foothills region of northeast British Columbia. Downward revisions to prior year bookings were made this year to West Beg and Town where Halfway natural gas production trends, which were believed to be stabilizing, continued to decline to the regional average decline curve. Many of these wells had been expected to stabilize at higher levels due to the higher initial production rates, however ultimate recoveries will still be above average due to the early flush period of approximately two years. At Gold Creek, a revision was made to reflect performance that was less than anticipated from a high rate well that was drilled late in 2006. Other revisions were experienced due to matching of hydrocarbon liquid ratios to 2007 performance on producing and future wells across the Foothills assets.

2007 FINDING, DEVELOPMENT AND NET ACQUISITION COSTS

Finding, development and acquisition costs ("FD&A") associated with the 2007 capital program and acquisitions completed during the year, including revisions and the change in future development capital, were $22.10 per proved boe and $16.67 per proved plus probable boe. On April 2, 2007 Progress acquired all of the issued and outstanding shares of a private company for $527.4 million, net of certain assets retained by the vendor and in conjunction with the acquisition, disposed of certain assets of the private company to ProEx Energy Ltd. ("ProEx") for $134.4 million, for a total net cost of $393.0 million. The amount allocated to property plant and equipment was $266.6 million, the difference is mainly comprised of a future income tax asset balance. The majority of the assets included in the acquisition are in the northeast British Columbia Foothills and the northwest Alberta Deep Basin regions. On May 31, 2007 Progress acquired certain petroleum and natural gas assets in the Wapiti area of the Deep Basin region for $40.9 million. There were no acquisitions or dispositions of a material nature in 2006 and 2005. Three year average FD&A costs, including revisions and the change in future development capital were $18.14 per proved boe and $14.20 per proved plus probable boe.

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	($ millions)	*(mmboe)*	*($/boe)*	*(mmboe)*	*($/boe)*
Total 2007 proved FD&A costs including future development costs	484.4	21.92	22.10	n/a	n/a
Total 2007 proved plus probable FD&A costs including future development costs	505.7	n/a	n/a	30.34	16.67
Three year average proved FD&A costs including future development costs	743.2	40.98	18.14	n/a	n/a
Three year average proved plus probable FD&A costs including future development costs	776.9	n/a	n/a	54.71	14.20

2007 FINDING AND DEVELOPMENT COSTS

Finding and development costs ("F&D") associated with the 2007 capital program, including revisions and the change in future development capital, were $20.97 per proved boe and $14.59 per proved plus probable boe. Three year average F&D costs, including revisions and the change in future development capital were $16.00 per proved boe and $12.59 per proved plus probable boe.

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	($ millions)	*(mmboe)*	*($/boe)*	*(mmboe)*	*($/boe)*
Total 2007 proved F&D costs including future development costs	181.4	8.65	20.97	n/a	n/a
Total 2007 proved plus probable F&D costs including future development costs	202.7	n/a	n/a	13.89	14.59
Three year average proved F&D costs including future development costs	439.6	27.47	16.00	n/a	n/a
Three year average proved plus probable F&D costs including future development costs	472.7	n/a	n/a	37.55	12.59

Reconciliation of Changes in Future Development Capital

In accordance with NI 51-101, the capital used to calculate FD&A and F&D costs has been adjusted to account for the change in future development capital. For that reason the capital may differ between the proved case and the proved plus probable case.

($ millions)	Proved	Change	Proved Plus Probable	Change
2007	78.91	44.41	120.92	65.71
2006	34.50		55.21	

RESERVE LIFE INDEX

The Trust's reserve life index ("RLI") using annualized fourth quarter production is 7.0 years proved (2006 – 7.3 years) and 9.8 years proved plus probable (2006 – 9.8 years).

	2007 Using Annualized Q4 Production	2007 Using 2008 GLJ Forecast Production	2006 Using Annualized Q4 Production	2006 Using 2007 GLJ Forecast Production
Production *(mmboe)*	8.848	9.537	6.592	7.091
Proved reserves *(mmboe)*	61.7	61.7	48.2	48.2
Proved RLI *(years)*	7.0	6.5	7.3	6.8
Production *(mmboe)*	8.848	10.088	6.592	7.641
Proved plus probable reserves *(mmboe)*	86.8	86.8	64.9	64.9
Proved Plus Probable RLI *(years)*	9.8	8.6	9.8	8.5

RESERVE REPLACEMENT

The Trust's 2007 capital program replaced production by a factor of 2.6 times on a proved basis (2006 – 1.4 times) and 3.6 times on a proved plus probable basis (2006 – 1.9 times). Reserve growth in 2007 was achieved through both acquisitions and the drill bit. Reserve growth in 2006 was achieved entirely through the drill bit.

	2007	2006
Production *(mmboe)*	**8.41**	6.52
Proved reserve additions *(mmboe)*	**21.92**	8.78
Proved placement ratio	**2.6**	1.4
Proved plus probable reserve additions *(mmboe)*	**30.34**	12.48
Proved plus probable replacement ratio	**3.6**	1.9

RECYCLE RATIO

The recycle ratio is a measure for evaluating the effectiveness of a company's reinvestment program. It accomplishes this by comparing the operating netback per boe to that year's reserve FD&A costs.

	2007	2006
Operating netback *($/boe)*	**29.11**	32.28
Proved FD&A costs after revisions of prior periods and including the change in future development costs *($/boe)*	**22.10**	16.20
Proved recycle ratio	**1.3**	2.0
Proved plus probable FD&A costs after revisions of prior periods and including the change in future development costs *($/boe)*	**16.67**	12.39
Proved plus probable recycle ratio	**1.7**	2.6

AFTER TAX NET ASSET VALUE

The Trust's after tax net asset value is measured with reference to the present value of future estimated cash flows from reserves estimates prepared by GLJ, the independent reserve engineers, and including undeveloped land, seismic data, adjustments for working capital deficiency, bank debt, convertible debentures and asset retirement obligations at year end. This calculation can vary significantly depending on the natural gas and oil price assumptions used by GLJ. This calculation does not represent a "going-concern" value since it only assumes the reserves contained in the GLJ report.

On October 25, 2007 the Alberta government announced the New Royalty Framework ("framework") which is proposed to take effect on January 1, 2009. The framework proposes a new simplified royalty formula for natural gas that will operate on a sliding scale determined by commodity prices, well productivity and drilling depth. The impact of the royalty increase is a decrease to the net present value of the Trust's reserves by approximately one to two percent when using a 10 percent discount rate and using GLJ forecast prices as at January 1, 2008. The table below does not include the framework as it has not become law.

	Discounted at 8%		Discounted at 10%	
($ millions, except per unit amounts)	**2007**	**2006**	**2007**	**2006**
Proved plus probable reserve value [1]	**1,436**	1,129	**1,316**	1,022
Undeveloped acreage [2]	**137**	81	**137**	81
Seismic [3]	**55**	36	**55**	36
Working capital deficiency	**(25)**	(14)	**(25)**	(14)
Bank debt	**(297)**	(75)	**(297)**	(75)
Convertible debentures	**(122)**	(120)	**(122)**	(120)
Asset retirement obligations [4]	**(27)**	(17)	**(24)**	(15)
After tax net asset value	**1,157**	1,020	**1,040**	915
Total units outstanding and issuable for exchangeable shares (thousands)	**110,781**	88,114	**110,781**	88,114
After tax net asset value per unit	**$10.44**	$11.58	**$9.39**	$10.38

[1] Reserve values are based on after tax estimates of future cash flows as evaluated by our independent qualified reserve evaluators using their future commodity price forecasts as presented above.

[2] Based on internal estimate of market value considering recent sales of similar properties in the same general area.

[3] Seismic inventory values are an internal estimate of replacement value.

[4] Proved plus probable reserve value includes $8.1 million and $7.4 million for the 8% and 10% discounted values, respectively (2006 - $6.9 and $5.7 million, respectively) for asset retirement obligations on wells with assigned reserves.

Progress Energy Trust

Management's Discussion and Analysis

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results, dated February 28, 2008, should be read in conjunction with Progress Energy Trust's ("Progress" or the "Trust") accompanying audited consolidated financial statements and related notes for the years ended December 31, 2007 and 2006. The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Non-GAAP Measurements Management uses cash flow from operations (before changes in non-cash working capital) ("cash flow") and diluted cash flow per unit to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating profit for the period nor should it be viewed as an alternative to operating profit, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The reconciliation between cash flow, as defined above, and cash flow from operations after changes in non-cash working capital for the years ended December 31, 2007 and 2006 is as follows:

($ thousands)	**2007**	2006
Cash flow (as defined above)	**214,290**	190,329
Changes in non-cash working capital	**6,139**	(170)
Cash flow from operations after changes in working capital	**220,429**	190,159

Management considers cash flow to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investments. Cash flow is used by research analysts to value and compare oil and gas trusts and is frequently included in published research when providing investment recommendations. Cash flow per unit is calculated using the diluted weighted average number of units for the period. All references to cash flow throughout the MD&A are based on cash flow before changes in non-cash working capital unless otherwise specified.

Management uses certain industry benchmarks such as operating netback and total debt to cash flow ratio to analyze financial and operating performance. These benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback and total debt to cash flow ratio are used by research analysts to compare operating performance and a trust's ability to maintain current distributions. Operating netback is the net result of the Trust's revenue net of realized gains and losses on financial instruments, and royalty, operating and transportation expenses as found in the accompanying audited consolidated financial statements. The total debt to cash flow ratio is calculated by dividing total debt at the end of the period (comprised of the working capital deficit, outstanding bank debt and the debt portion of the Trust's convertible unsecured debentures) by the 12 month trailing cash flow as defined above.

Forward Looking Statements - Certain information regarding Progress set forth in this document, including Management's assessment of Progress' future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Progress' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal and external sources. Progress' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Progress will derive therefrom.

DESCRIPTION OF BUSINESS

Progress is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties. Progress Energy Ltd., a wholly owned subsidiary of Progress, carries on the business of the Trust and directly owns the petroleum and natural gas properties and assets related thereto. The Trust's unitholders and

exchangeable shareholders are the sole beneficiaries of the Trust. Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust which is primarily comprised of interest earned on debt notes issued to Progress Energy Ltd., as well as, amounts attributed to a net profits interest agreement entered into with Progress Energy Ltd. The aggregate amounts received by the Trust each period are based on the consolidated cash flow each period, as adjusted on a discretionary basis, for cash withheld to fund capital expenditures.

Progress is a Calgary based, natural gas focused, trust targeting sustainable production and reserves per trust unit through utilization of its technical capability and capital investment efficiencies. Primary operating areas include the Deep Basin of northwest Alberta and the northeast British Columbia Foothills and Fort St. John Plains regions. Trust units of Progress trade on the Toronto Stock Exchange ("TSX") under the symbol PGX.UN. Exchangeable shares and the 6.75 percent and 6.25 percent convertible unsecured subordinated debentures (the "Debentures") of Progress trade on the TSX under the symbols PGE, PGX.DB and PGX.DB.A, respectively.

RELATIONSHIP WITH PROEX

The Trust provides personnel and certain administrative and technical services to ProEx Energy Ltd. ("ProEx") in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Trust provides these services in accordance with the technical services agreement ("Technical Services Agreement") entered into with ProEx as described below. ProEx has granted stock options and shares to employees and executives of Progress as service providers and has also participated in a long term incentive plan by granting ProEx common shares to employees of Progress, excluding the executives. To facilitate this plan, during 2007, Progress purchased 173,789 ProEx common shares and has been reimbursed by ProEx for the cost incurred. The ProEx common shares will be held until the vesting date, two years from date of grant. Any forfeited shares will revert back to ProEx.

The Trust and ProEx have joint interest in certain properties and undeveloped land in the northeast British Columbia Foothills and Fort St. John Plains regions. These joint interest properties are governed by standard industry agreements and in addition the Trust has entered into a protocol arrangement ("Protocol Arrangement") with ProEx that specifies how each company will manage the joint lands in specifically identified areas of interest. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

On April 2, 2007, Progress acquired all of the issued and outstanding shares of a private company for $527.4 million, net of certain assets retained by the vendor. In conjunction with the acquisition, on April 2, 2007, Progress disposed of certain assets of the private company to ProEx for $134.4 million. When considering the bid process for the acquisition, each of Progress and ProEx identified assets that they were interested in acquiring and values that they were willing to pay to acquire such assets. Progress made a single bid on behalf of ProEx and Progress and the ultimate purchase price was based on the prices that each of Progress and ProEx were willing to pay for the assets that they had selected to acquire. The resale of assets from Progress to ProEx was based on these allocations. The technical services committee reviewed the details of the transaction prior to the purchase and sale agreement being signed. All lands are managed in accordance with the Protocol Arrangement.

On November 30, 2007, Progress and ProEx jointly acquired certain assets in the Foothills region of British Columbia. The total cost of the acquisition of $17.9 million was split in accordance with working interests currently held in the surrounding area. As a result, Progress acquired a 20 percent interest in the assets ($3.6 million) and ProEx an 80 percent interest ($14.3 million).

Technical Services Agreement

The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. The Trust provides services including management, development, exploitation, operations, administrative, and marketing, as well as, information technology systems to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx.

Protocol Arrangement

The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. The Protocol Arrangement also outlines the practices to be followed in the event either party enters into areas outside of the identified areas of interest.

CORPORATE ACQUISITION

On April 2, 2007, Progress acquired all of the issued and outstanding shares of a private company for $527.4 million, net of certain assets retained by the vendor ("Corporate Acquisition"). In conjunction with the Corporate Acquisition, on April 2, 2007, Progress disposed of certain assets of the private company to ProEx for $134.4 million. The resulting net cash consideration of $393.0 million was financed by the issuance of 21,000,000 trust units at a price of $12.00 per trust unit for proceeds of $252.0 million ($238.7 million net of issue costs) and through increased bank debt. Included in the Corporate Acquisition was approximately $720.9 million of tax pools which are available to Progress to shelter future taxable income resulting in the recognition of a $137.2 million future income tax asset.

The Corporate Acquisition included approximately 6,400 boe per day of production, 95 percent natural gas and approximately 240,000 net acres of undeveloped land.

OPERATING SUMMARY

In accordance with Canadian industry practice, production volumes, reserve volumes and revenues are reported on a Trust interest basis (working interest plus royalty interest), before deduction of crown and other royalties, unless otherwise indicated. The Trust's results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for this production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather and general economic conditions and changes in the Canadian/United States currency exchange rate.

In this MD&A, production and reserves information may be presented on a "barrel of oil equivalent" or "boe" basis with six thousand cubic feet ("mcf") of natural gas being equivalent to one barrel ("bbl") of crude oil or natural gas liquids. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well-head.

Production

	Fourth Quarter of 2007	Fourth Quarter of 2006	**2007**	2006	Change
Daily Production					
Natural gas *(mcf/d)*	**123,740**	88,568	**116,630**	85,749	36%
Crude oil *(bbls/d)*	**2,068**	2,030	**2,147**	2,196	(2)%
Natural gas liquids *(bbls/d)*	**1,548**	1,269	**1,446**	1,366	6%
Total daily production *(boe/d)*	**24,240**	18,060	**23,031**	17,853	29%
Natural gas as a % of total production	**85%**	82%	**84%**	80%	

Production in 2007 averaged 23,031 boe per day consisting of 116,630 mcf per day of natural gas, 2,147 bbls per day of crude oil and 1,446 bbls per day of natural gas liquids. This production was 29 percent higher than 2006 with production averaging 17,853 boe per day due to the Corporate Acquisition and successful drilling results. Production for 2007 was within Management's expectations for the year and the assets acquired through the Corporate Acquisition are performing as expected. The Trust replaced 361 percent of production on a proved plus probable basis, resulting in a finding, development and acquisition cost of $16.67 per proved plus probable boe. The Trust's production portfolio in 2007 was weighted 84 percent to natural gas, 10 percent to crude oil and six percent to natural gas liquids.

Natural gas production increased 36 percent in 2007 to 116,630 mcf per day compared to 85,749 mcf per day in 2006. The increase was due to the Corporate Acquisition as well as, successful drilling results in late 2006 and through 2007

in Progress' core regions. Production in the last half of 2007 was hampered by wet field conditions which delayed drilling and tie-in work. The 2006 natural gas production was negatively impacted by scheduled plant maintenance turnarounds in several areas including Karr, Gold Creek-Dunes, Two Creek, Strachan and Gilby in Alberta and the Fort Nelson gas processing facility in British Columbia.

Crude oil and natural gas liquids production in 2007 of 3,593 bbls per day was slightly higher than 2006 of 3,562 bbls per day.

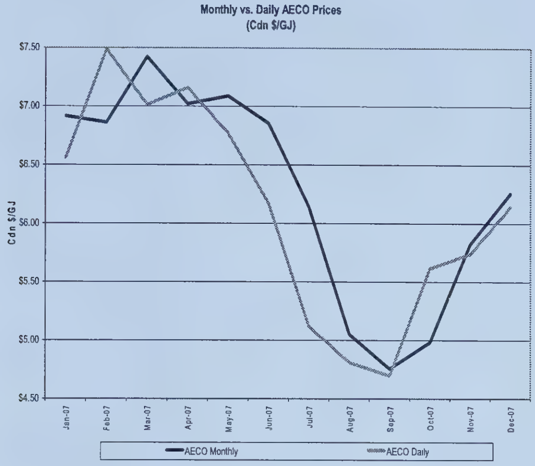
The Trust's 2007 fourth quarter production averaged 24,240 boe per day, comprised of 123,740 mcf per day of natural gas, 2,068 bbls per day of crude oil and 1,548 bbls per day of natural gas liquids. This was higher than the fourth quarter of 2006 which averaged 18,060 boe per day, comprised of 88,568 mcf per day of natural gas, 2,030 bbls per day of crude oil and 1,269 bbls per day of natural gas liquids. The difference was due to the Corporate Acquisition and successful drilling. For a full analysis of fourth quarter production refer to the Fourth Quarter Analysis section in this MD&A.

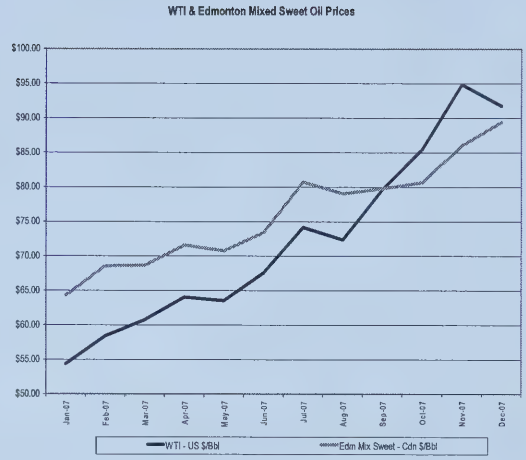
Progress' December 2007 production averaged approximately 25,000 boe per day and Management anticipates production to average approximately 23,500 boe per day in 2008 dependent on the actual capital invested. This forecast is inclusive of a major turnaround at the McMahon gas plant in northeast British Columbia that is scheduled in June 2008, and natural reservoir declines. Capital investment in 2008 is forecasted to be between $110 million to $125 million.

Production by Region

(boe/d)	**Fourth Quarter 2007**	Fourth Quarter 2006	Change	**2007**	2006	Change
Foothills	**6,434**	3,769	71%	**5,814**	3,690	58%
Fort St. John Plains	**1,949**	2,118	(8)%	**1,993**	2,098	(5)%
Deep Basin – Ojay	**989**	-		**782**	-	
Other	**285**	348	(18)%	**319**	369	(14)%
Total British Columbia	**9,657**	6,235	55%	**8,908**	6,157	45%
Deep Basin	**12,030**	9,099	32%	**11,412**	8,825	29%
Central Alberta	**1,706**	1,714	-%	**1,840**	1,742	6%
Other	**621**	736	(16)%	**630**	803	(22)%
Total Alberta	**14,357**	11,549	24%	**13,882**	11,370	22%
Saskatchewan	**226**	276	(18)%	**241**	326	(26)%
Total daily production	**24,240**	18,060	34%	**23,031**	17,853	29%

Pricing and Risk Management





Natural Gas Markets

Progress' realized natural gas price for the year ended December 31, 2007 was $6.85 per mcf (2006 - $7.19 per mcf) compared to the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system ("AECO") daily index average of $6.11 per gigajoule ("gj") and the AECO monthly index average of $6.27 per gj (2006 - $6.17 per gj and $6.62 per gj, respectively). Progress markets its natural gas at a mix of daily and monthly pricing.

The first quarter of 2007 began with moderate weather and weak demand for natural gas. However, mid January brought unexpected winter storms and colder than normal weather across Canada and the northeastern United States ("US"). The resulting demand for natural gas created some of the largest monthly storage withdrawals in several years as supplies shrank below the benchmark 5 year average and recovered from the high levels reached in the fall of 2006. By the end of February, AECO gas prices had traded at the highest point they would see for the rest of 2007. The second quarter was typical of any shoulder season as moderate weather throughout most of the continent created minimal gas demand for either heating or cooling. Market pricing remained relatively flat while gas demand to re-fill storage absorbed any lower priced excess supply. Moderate weather throughout a majority of North America created minimal demand for natural gas during the third quarter. The supply situation was further compounded by the addition of substantial liquefied natural gas ("LNG") import volumes. The resulting situation created a buyers market for natural gas storage purchasers as they bought significant volumes in order to benefit from the declining prices of the over-supplied market. Gas prices continued to suffer from bearish fundamentals through October as warmer than normal weather and record high storage volumes created significant downward pressure. Crude oil prices which had steadily increased during the year jumped to new highs which provided price support to natural gas through the increased price of heating oil. Winter weather forecasts calling for colder than normal temperatures initially supported gas prices until those same forecasts were revised for warmer temperatures early in November. The week ending November 8th saw storage hit a total of 3.545 Tcf for a new all-time high which market analysts expected to be sufficient to cover any likely winter gas demand scenario. Late November saw cold weather move into the northeastern US which had previously been forecast to warm through December. However, as the days passed, the forecast warming trend continued to be deferred but never actually occurred in December. The resulting storage withdrawals during December eliminated a sizable portion of the year over year surplus and statistically placed the December 2007 storage total well within the 5 year average band.

Even though high storage volumes and the resulting oversupply of natural gas weighed heavily on prices through the year, prices for 2007 averaged US$6.91 per million btu for the New York Mercantile Exchange ("NYMEX") and $6.11 per gj at AECO.

Oil

Although crude oil prices have achieved record highs throughout 2007 peaking at US$95.58 per barrel and averaging US $72.24 per barrel for the full year, the strengthening of the Canadian dollar relative to the US dollar was responsible for eroding most of the gains and negatively impacted the price of crude oil in Canadian dollar terms. Progress' realized prices for its liquids streams for the year ended December 31, 2007 were $72.86 per bbl (2006 - $67.88 per bbl) for crude oil and $62.77 per bbl (2006 - $62.65 per bbl) for natural gas liquids.

Looking toward 2008, we anticipate WTI oil prices will average within the US$80.00 to US$90.00 per bbl range and AECO natural gas to average between $7.00 to $7.50 per gj with the Canadian\US exchange rate trading at par. Progress produces predominantly light oil and high heat content liquids rich natural gas that attract premium market prices.

Commodity Prices

	2007	2006	Change
Average Benchmark Prices			
Natural gas - AECO (daily) *($/gj)*	**6.11**	6.17	(1)%
Natural gas - AECO (monthly) *($/gj)*	**6.27**	6.62	(5)%
Natural gas - Station #2 (daily) *($/gj)*	**6.05**	5.90	3%
Crude oil - WTI *(US$/bbl)*	**72.24**	66.22	9%
Crude oil - Edmonton par price *(Cdn$/bbl)*	**76.06**	72.74	5%
Exchange rate – *(US$/Cdn$)*	**1.0740**	1.1343	(5)%

Average Realized Prices			
Natural gas *($/mcf)*	**6.85**	7.19	(5)%
Crude oil *($/bbl)*	**72.86**	67.88	7%
Natural gas liquids *($/bbl)*	**62.77**	62.65	-%

Natural Gas Pricing

US natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta natural gas is referenced off the AECO Hub and British Columbia natural gas off of Sumas Washington or Station #2 market centers. Virtually all of Progress' natural gas is sold at market prices at one of the Alberta or British Columbia hubs. Progress typically sells 50 percent of its natural gas production on monthly indexes and 50 percent on daily indexes.

Natural Gas Production and Prices by Province

	2007		2006	
	mcf/d	**$/mcf**	mcf/d	$/mcf
Alberta	**69,419**	**7.02**	54,268	7.32
British Columbia	**46,992**	**6.62**	30,882	6.98
Saskatchewan	**219**	**5.37**	599	6.47
Total production and average sales price	**116,630**	**6.85**	85,749	7.19

Alberta Natural Gas Prices

	2007	2006
NYMEX *(US$/mmbtu 12 month average – last 3 days)*	**6.91**	7.26
Less: AECO basis differential to Henry Hub *(US$/mmbtu)*	**(0.91)**	(1.52)
AECO *(US$/mmbtu)*	**6.00**	5.74
Average exchange rate	**1.0740**	1.1343
AECO price *(Cdn$/mmbtu daily average)*	**6.44**	6.51
Premium: Progress realized price vs spot(1)	**0.58**	0.81
Progress average realized Alberta price *(Cdn$/mcf)*	**7.02**	7.32

(1) Includes the conversion of mmbtu's to mcf.

British Columbia Natural Gas Prices

	2007	2006
NYMEX *(US$/mmbtu 12 month average – last 3 Days)*	**6.91**	7.26
Less: Station #2 basis differential to Henry Hub *(US$/mmbtu)*	**(0.97)**	(1.78)
Station #2 *(US$/mmbtu)*	**5.94**	5.48
Average exchange rate	**1.0740**	1.1343
Station #2 price *(Cdn$/ mmbtu daily average)*	**6.38**	6.22
Premium: Progress realized price vs. spot(1)	**0.24**	0.76
Progress average realized British Columbia price *(Cdn$/mcf)*	**6.62**	6.98

(1) Includes the conversion of mmbtu's to mcf.

Price Risk Management

The Trust has entered into several natural gas financial contracts for the purpose of protecting its cash flow from the volatility of natural gas prices. For the year ended December 31, 2007, the Trust's natural gas price risk management program had a net realized gain of $16.1 million (2006 - $29.9 million).

On January 1, 2007 the Trust adopted the new accounting standards regarding the accounting for financial instruments. In addition to the adoption of the new standards, Management elected not to use hedge accounting and therefore, records the fair value of its natural gas financial contracts at each reporting period with the change in the fair value being classified as unrealized gains or losses on the statement of earnings. The accounting for hedging relationships for prior fiscal periods are not retroactively changed, therefore, there was no restatement of the financial position or results of operation as at and for the year ended December 31, 2006.

On January 1, 2007 the fair value of the commodity price contracts was an asset of $15.6 million and resulted in an increase to accumulated other comprehensive income and the future income tax liability of $10.5 million and $5.1 million, respectively. The $10.5 million recognized in accumulated other comprehensive income was amortized over the term of the contracts through other comprehensive income with a corresponding unrealized gain on financial instruments on the statement of earnings. As a result, for the year ended December 31, 2007 $10.5 million, net of tax, was charged to other comprehensive income with a corresponding unrealized gain on financial instruments of $15.6 million and a charge to future income tax expense of $5.1 million. The unrealized gain of $15.6 million was offset by the change in fair value of the commodity price contracts from January 1, 2007 of $15.6 million resulting in a net unrealized gain of nil for 2007.

The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. The Risk Management Policy has the following objectives:

- To reduce risk exposure to budgeted annual cash flow projections resulting from uncertainty or changes in commodity prices, interest rates or foreign exchange.
- To provide greater certainty and stability to monthly distributions.
- To limit the permissible structures to ensure hedging effectiveness.
- To limit hedging up to a maximum of 50 percent of budgeted production before royalties.
- To limit hedging activity to counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

There were no natural gas financial instruments outstanding as at December 31, 2007. Subsequent to December 31, 2007 Progress entered into several derivative financial instruments for the following production volumes:

Financial Price Risk Management	Contract Natural Gas Volumes ('000 gj/d)	% of Estimated of Production
First quarter of 2008	-	-
Second quarter of 2008	80	50
Third quarter 2008	80	50
Fourth quarter 2008	27	17

Sensitivities

The Trust's risk management program will reduce, but not eliminate, the effects of changing commodity prices and interest rates and as a result cash flow remains sensitive to these changes as demonstrated by the following table:

($ thousands)	Estimated Effect on 2008 (1) Cash Flow per Trust Unit
Change of $0.25 per mcf in the price of natural gas	8,300
Change of $5.00 per barrel in the price of crude oil	3,500
Change of 5,000 mcf/d in natural gas production	9,500
Change of 500 bbls/d in crude oil production	10,900
Change of 1% in prime interest rates	3,250

(1)These sensitivities reflect all commodity contracts as described in Note 11 of the consolidated financial statements. They apply to prices, production, and interest rates within the context of current market rates. The sensitivities above will no longer apply above the ceiling or below the floor price limits set by existing natural gas financial contracts.

Revenue

Petroleum and natural gas revenue increased 23 percent to $382.1 million in 2007 from $310.5 million in 2006 mainly due to higher natural gas production as a result of the Corporate Acquisition and successful drilling. Production averaged 23,031 boe per day in 2007 compared to 17,853 boe per day in 2006 while realized commodity prices decreased five percent to $45.45 per boe in 2007 from $47.66 per boe in 2006. Petroleum and natural gas revenue in 2007 consisted of $291.3 million from natural gas sales, $57.1 million from crude oil sales and $33.1 million from the sale of natural gas liquids.

($ thousands)	**2007**	2006	Change
Natural gas sales	**291,830**	224,892	30%
Crude oil sales	**57,096**	54,402	5%
Natural gas liquids sales	**33,126**	31,224	6%
Petroleum and natural gas revenue	**382,052**	310,518	23%

($ thousands)	Natural Gas	Crude Oil & NGLs	Total
2006 Petroleum and natural gas revenue	224,892	85,626	310,518
Price variance	(14,053)	3,851	(10,202)
Production variance	80,991	745	81,736
2007 Petroleum and natural gas revenue	**291,830**	**90,222**	**382,052**

Royalties

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners. Effective for 2007, the Alberta government eliminated the Alberta royalty tax credit program. The impact to Progress was an increase to royalty expense for the year ended December 31, 2007 of $0.5 million.

Royalties increased seven percent to $84.4 million in 2007 from $78.8 million in 2006 due to higher revenues, as a result of higher production. The Trust's average royalty rate in 2007 was 22.1 percent compared to 25.4 percent in 2006. The decrease in the royalty rate is due to lower royalty rates on the properties acquired in the Corporate Acquisition, as well as, the acquired properties included wells in which Progress paid gross over riding royalties.

On October 25, 2007 the Alberta government announced the New Royalty Framework ("framework"), which is proposed to take effect on January 1, 2009. Progress has reviewed the information currently provided by the government and believes that the changes to Alberta royalties may increase Progress' Alberta royalty rate from 27 percent to 31.5 percent based on current production and a realized natural gas price of $7.00 per gj. Using the same

production and price assumptions, Progress' royalty rate is estimated to increase marginally from 25 percent to 27.5 percent, on a corporate basis, resulting in an approximate five percent reduction in 2009 cash flow.

The framework proposes a new simplified royalty formula for natural gas that will operate on a sliding scale determined by commodity prices, well productivity and drilling depth. Progress' Deep Basin well depths range between 2,300 to 2,700 meters which will be eligible for the new measured depth drilling formula. Progress is attracted to the Deep Basin region because of the quality and pedigree of the region with its higher than average well productivity and multi zone drilling targets. The new royalty formula will increase Progress' royalties payable but is not expected to materially impact the economics of drilling in the Deep Basin. However, Progress does have the opportunity to shift its capital investment program into British Columbia. In 2007 61 percent of Progress' revenue was from the province of Alberta down from 64 percent in 2006 due to Progress' growing British Columbia Foothills production.

($ thousands)	**2007**	2006
Crown	**72,880**	64,544
Freehold and overriding	**11,554**	14,218
Total royalty expense	**84,434**	78,762
Royalties *($/boe)*	**10.04**	12.09
Average royalty rate *(%)*	**22.1**	25.4

The following table provides a break down of royalties by product:

($ thousands)	**2007**	2006
Natural gas royalties	**63,944**	56,945
$/boe	**9.02**	10.92
Average natural gas royalty rate (%)	**21.9**	25.4
Crude oil royalties	**10,733**	12,856
$/boe	**13.70**	16.04
Average crude oil royalty rate (%)	**18.8**	23.6
Natural gas liquids royalties	**9,757**	8,961
$/boe	**18.49**	17.97
Average natural gas liquids royalty rate (%)	**29.5**	28.7

Management anticipates, based on current commodity prices that the average royalty rate for 2008 will be approximately 23 to 24 percent of petroleum and natural gas revenue.

Operating Expenses

Operating expenses increased 33 percent to \$53.7 million in 2007 compared to \$40.4 million in 2006. The increase is the result of higher production in 2007 compared to 2006, reflecting the impact of the Corporate Acquisition and successful drilling. On a boe basis, operating expenses for 2007 increased three percent to \$6.38 from \$6.19 in 2006. The operating expense per boe trended downwards in late 2007 as a result of benefits realized from optimizing the acquired assets. Progress has experienced increased costs for well servicing, insurance, workovers and well maintenance. Through increased operating efficiencies and the addition of low operating cost per boe production, the Trust has been able to offset a large portion of these increases and keep operating costs per boe low. Management anticipates continuing this trend and forecasts operating expenses for 2008 to be between \$6.50 to \$6.75 per boe.

(\$ thousands)	**2007**	2006	Change
Operating expenses - total	**53,661**	40,353	
\$/boe	**6.38**	6.19	3%
Operating expenses - natural gas properties	**43,524**	31,381	
\$/boe	**5.79**	5.62	3%
Operating expenses - crude oil properties	**10,137**	8,972	
\$/boe	**11.37**	9.61	18%

Transportation Expenses

Transportation expenses increased 40 percent to \$15.4 million in 2007 compared to \$11.0 million in 2006. The increase is due to higher production in 2007 compared to 2006. On a boe basis, transportation expenses in 2007 increased eight percent to \$1.83 compared to \$1.69 in 2006. The increase is due to higher transportation and treatment tolls associated with the Corporate Acquisition including higher treatment tolls associated with the Slave Point production at the Bubbles property in the Foothills region. In British Columbia, there is an infrastructure owned by Spectra Energy that enables gas producers to avoid facility construction in exchange for gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Operating Netbacks

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the higher proportion of natural gas or crude oil production. The following table summarizes the operating netbacks for natural gas properties, oil properties and all properties combined:

	2007	2006
Natural Gas Properties ($/mcf)		
Sales price	**7.16**	7.53
Realized gain on financial instruments	**0.37**	0.89
Royalties	**(1.61)**	(1.94)
Operating expenses	**(0.95)**	(0.94)
Transportation expenses	**(0.30)**	(0.28)
Operating netback – natural gas properties	**4.67**	5.26
Oil Properties ($/bbl)		
Sales Price	**66.40**	62.62
Royalties	**(13.48)**	(14.74)
Operating expenses	**(11.37)**	(9.61)
Transportation expenses	**(1.93)**	(1.89)
Operating netback – oil properties	**39.62**	36.38
All Properties ($/boe)		
Sales Price	**45.45**	47.66
Realized gain on financial instruments	**1.91**	4.59
Royalties	**(10.04)**	(12.09)
Operating expenses	**(6.38)**	(6.19)
Transportation expenses	**(1.83)**	(1.69)
Operating netback – all properties	**29.11**	32.28

General and Administrative Expenses

General and administrative expenses net of overhead recoveries on operated properties, ("G&A") increased 39 percent to $8.8 million ($1.04 per boe) in 2007 compared to $6.3 million ($0.97 per boe) in 2006. The increase in G&A for the year over 2006 is due to the increased size of the Trust, as well as higher costs incurred to retain employees.

($ thousands)	**2007**	2006
Gross G&A	**20,934**	16,171
Technical Services Fees from ProEx	**(6,248)**	(4,484)
Operator recoveries	**(4,418)**	(4,132)
Capitalized expenses	**(1,512)**	(1,234)
Total G&A expense	**8,756**	6,321
G&A ($/boe)	**1.04**	0.97

In accordance with the Technical Services Agreement with ProEx, the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expenses reimbursed by ProEx in 2007 were $6.2 million compared to $4.5 million in 2006.

The magnitude of operator recoveries is a function of activity levels and the degree to which operations are operated by the Trust. Progress operates 79 percent of its production and operates the majority of the drilling and construction activity. Operator recoveries were $4.4 million for 2007 compared to $4.1 million in 2006, the increase being a result of operated wells acquired during 2007.

The Trust capitalized approximately $1.5 million of G&A in 2007 and $1.2 million in 2006. The majority of these costs represent geological and geophysical employee compensation.

Management anticipates G&A expense to remain consistent with 2007 and average in the range of $1.00 to $1.10 per boe in 2008.

Unit Based Compensation Expenses

The Trust's Performance Unit Incentive Plan (the "Plan") provides for employees and directors to be granted performance units by the Board of Directors of Progress Energy Ltd. from time to time at its sole discretion. The Plan was modified in 2007 to include a new long term incentive component ("LTI component") for non-executive employees.

Performance Units

The performance units will vest on the third anniversary of the date of grant and actual payment will be determined based on the performance of the Trust relative to its peers. Performance factors range from 0.5 to 1.5 times the initial performance units granted except for performance units granted to the Trust's executives in 2007 which can range from 0 to 3 times. Over the three year term the performance units will attract distributions. The Trust expects to pay out the distribution portion in cash while the units earned will be issued from treasury.

Long Term Incentive Component

Awards granted under the LTI component of the Plan will vest over three years with 40 percent vesting on the second anniversary of the date of grant and 60 percent vesting on the third anniversary of the date of grant. An additional 15 percent grant will be paid if the holder holds the units received on the second anniversary date for one additional year. As at December 31, 2007, 189,485 units are outstanding under the LTI component at an average value of $14.00 per unit, resulting in a total compensation cost of $2.7 million of which $2.3 million will be recognized through unit based compensation expense and $0.4 million will be capitalized over the vesting period.

On June 28, 2007 381,367 units were issued to settle the performance units that vested on July 2, 2007, resulting in $5.1 million being transferred from contributed surplus to unitholders' capital.

As at December 31, 2007 there are 481,800 performance units outstanding that were granted in 2005. During 2007 the estimated performance factor for this grant was increased from 1.0 to 1.5 based on the Trust's operating performance. The fair value of the performance units using a performance factor of 1.5 is approximately $10.9 million of which $9.6 million will be amortized through unit based compensation expense and $1.3 million will be capitalized over the vesting period with a corresponding increase to contributed surplus. Actual performance factors will not be determined until the end of the performance period.

As at December 31, 2007 there are 401,850 performance units outstanding that were granted in 2006. During 2007 the estimated performance factor for this grant was increased from 1.0 to 1.5 based on the Trust's operating performance. The fair value of the performance units using a performance factor of 1.5 is approximately $9.1 million of which $8.0 million will be amortized through unit based compensation expense and $1.1 million will be capitalized over the vesting period with a corresponding increase to contributed surplus. Actual performance factors will not be determined until the end of the performance period.

As at December 31, 2007 there are 504,550 performance units outstanding that were granted in 2007. The fair value of the performance units using a performance factor of 1.0 is approximately $6.5 million of which $5.8 million will be amortized through unit based compensation expense and $0.7 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

For the year ended December 31, 2007 unit based compensation expense increased 85 percent to $9.0 million ($1.08 per boe) compared to $4.9 million ($0.75 per boe) in 2006. In 2007, $1.9 million of unit based compensation was capitalized compared to $0.8 million in 2006. The increase is due to the performance units and LTI component units granted in 2007, as well as an increase in the performance factor during 2007 from 1.0 to 1.5 on the performance units vesting in 2008 and 2009 due to the Trust's strong operating performance relative to its peers. Actual performance factors will not be determined until the end of the three year performance periods.

Management anticipates unit based compensation expenses will average approximately $1.10 per boe in 2008.

	2007	2006
Performance Units		
Balance, beginning of year	1,300,717	899,567
Granted	521,450	424,950
Settled	(381,367)	-
Forfeited	(52,600)	(23,800)
Balance, end of year	1,388,200	1,300,717
Vesting Date		
2007	-	380,567
2008[1]	481,800	512,300
2009[1]	401,850	407,850
2010	504,550	-
Total	1,388,200	1,300,717

(1) Using the current anticipated performance factor of 1.5 times, 722,700 units and 602,775 units, respectively, will be issued on the vesting of the 2005 and 2006 performance units in 2008 and 2009.

	2007	2006
Units under LTI Component		
Balance, beginning of year	-	-
Granted	198,629	-
Forfeited	(9,144)	-
Balance, end of year	189,485	-
Vesting Date		
2009	75,794	-
2010	113,691	-
Total[1]	189,485	-

(1) If the units vesting in 2009 are held by the LTI holder until 2010, one year past the date of vesting, an additional 28,423 units will be issued by the Trust.

Interest and Financing Expenses

Interest and financing expenses in 2007 increased 95 percent to $23.0 million compared to $11.8 million in 2006. The increase is due to the increase in bank debt to fund a portion of the Corporate Acquisition and capital expenditures during 2007, as well as the issuance of the 6.25 percent convertible unsecured subordinated debentures in August of 2006.

Debenture interest, accretion and amortized issue costs relate to two debenture issues; the 6.75 percent debentures issued on February 2, 2005 and the 6.25 percent debentures issued on August 22, 2006 (the "Debentures"). For more information regarding the Debentures, see the "Liquidity and Capital Resources" section below.

($ thousands)	**2007**	2006
Interest on bank debt	**11,997**	4,406
Interest on Debentures	**8,449**	5,803
Amortization of Debenture issue costs	**1,116**	717
Accretion on debt portion of Debentures[(1)]	**1,453**	872
Total interest and financing expense	**23,015**	11,798
Interest and financing expense *($/boe)*	**2.74**	1.81
Average bank debt outstanding	**219,562**	86,622
Average bank debt interest rate *(%)*	**5.5**	5.1
Average bank prime lending rate *(%)*	**6.1**	5.8

(1) Under Canadian GAAP, the fair value of the conversion feature of the Debentures is classified as equity and the remainder is classified as debt. Over the term of the Debentures, the debt portion will accrete up to the principal balance at maturity with the charge going to interest and financing expenses.

Depletion, Depreciation and Accretion

Depletion and depreciation of property, plant and equipment and the accretion of the asset retirement obligations ("DD&A") increased 46 percent to $138.6 million in 2007 compared to $94.7 million in 2006. This resulted in DD&A per boe in 2007 of $16.49 compared to $14.53 recognized in 2006. The increase is due to the Corporate Acquisition.

($ thousands)	**2007**	2006
Depletion	**135,498**	92,287
Depreciation	**722**	671
Accretion of asset retirement obligations	**2,416**	1,750
Total DD&A expense	**138,636**	94,708
DD&A ($/boe)	**16.49**	14.53

Income and Capital Taxes

In June, 2007 the federal government's bill regarding the taxation of distributions from trusts beginning January 1, 2011 was enacted. As a result, a recovery of $6.6 million was recognized in the future income tax provision on the recognition of a $6.6 million future income tax asset in the Trust. Previously, the future income tax liability on the consolidated balance sheet represented only the future income tax liability of the Trust's subsidiary.

As part of the government's bill, a growth limit was established for existing trusts by limiting new equity issues to 40 percent of that trust's October 31, 2006 market capitalization ("benchmark") for 2007, and an additional 20 percent of the benchmark for each of 2008, 2009 and 2010. For Progress, the growth limits are $476.8 million for 2007 (less $252.0 million as a result of the equity offering in regards to the Corporate Acquisition) and $238.4 million for each of 2008, 2009 and 2010 with any unused amount rolling forward to the next year.

The provision for future income taxes for 2007 was a recovery of $14.9 million compared to a recovery of $14.7 million for 2006. The recovery in 2007 was the result of lower earnings as well as the recognition of the future income tax asset of the Trust of $6.6 million noted above. These were partially offset by a charge of $2.3 million due to a

reduction in future federal and provincial tax rates that reduced the value of Progress' future tax asset. The substantial recovery in 2006 is due to a reduction in future federal and provincial income tax rates enacted during that year.

As a result of the Corporate Acquisition, Progress recognized a $137.2 million future income tax asset for the difference between the $720.9 million in tax pools acquired over the value assigned to the assets. Progress' estimated tax pool balances as at December 31, 2007 total approximately $1.2 billion.

Non-Controlling Interest – Exchangeable Shares

The exchangeable shares of the Trust's subsidiary trade on the TSX, thereby allowing holders of the exchangeable shares to dispose of them without having to exchange them for trust units and consequently, they must be classified as non-controlling interest outside of unitholders' equity. The net earnings attributable to the exchangeable shares is charged to the consolidated statements of earnings as non-controlling interest expense with a corresponding increase to non-controlling interest on the consolidated balance sheet.

The following details the non-controlling interest activity for the years ended December 31, 2007 and 2006:

	2007		2006	
Exchangeable shares *($ thousands, except unit amounts)*	**Number**	**Amount**	Number	Amount
Balance, beginning of year	**9,642,540**	**122,592**	11,388,751	127,205
Exchanged for trust units	**(469,457)**	**(6,132)**	(1,746,211)	(20,130)
Non-controlling interest expense		**9,924**		15,517
Balance, end of year	**9,173,083**	**126,384**	9,642,540	122,592

The charge to net earnings of $9.9 million for 2007 and $15.5 million for 2006 represents the net earnings attributable to the exchangeable shares.

Net Earnings and Cash Flow

Net earnings decreased 23 percent to $70.2 million in 2007 compared to $91.6 million in 2006. Lower natural gas prices and higher DD&A expense in 2007 exceeded the impact of higher production as a result of the Corporate Acquisition. Basic net earnings in 2007 were $0.76 per trust unit compared to $1.23 per trust unit in 2006. Diluted net earnings in 2007 were $0.76 per trust unit compared to $1.21 per trust unit in 2006.

Other comprehensive income for 2007 includes a charge of $10.5 million compared to nil for 2006 relating to the amortization of the amount recognized in accumulated other comprehensive income on January 1, 2007 for the fair value of financial instruments on adoption of the new accounting standards for financial instruments (refer to Risk Management above). This resulted in total comprehensive income for 2007 of $59.7 million compared to $91.6 million in 2006.

Cash flow increased 13 percent to $214.3 million in 2007 compared to $190.3 million in 2006 due to higher revenues as a result of the Corporate Acquisition. Diluted cash flow in 2007 was $2.02 per trust unit compared to $2.16 per trust unit in 2006.

Quarterly Financial Summary[1,2]

($ thousands, except per unit amounts)	Three Months Ended Dec 31 2007	Sept 30 2007	June 30 2007	Mar 31 2007	Dec 31 2006	Sept 30 2006	June 30 2006	Mar 31 2006
Petroleum and natural gas revenue	**99,592**	88,480	108,503	85,477	75,182	72,328	71,439	91,568
Cash flow	**54,727**	48,085	58,398	53,080	49,603	47,218	45,871	47,637
Per unit diluted	**0.49**	0.43	0.53	0.60	0.56	0.54	0.52	0.55
Net earnings	**9,922**	11,909	31,947	16,425	21,538	20,252	28,425	21,383
Per unit basic	**0.10**	0.12	0.33	0.22	0.29	0.27	0.38	0.29
Per unit diluted	**0.10**	0.12	0.33	0.22	0.28	0.27	0.38	0.29

(1) Certain amounts above have been adjusted to conform to the presentation adopted in 2007 as a result of the adoption of the new accounting standards for financial instruments.

(2) Petroleum and natural gas revenue and cash flow for second and third quarters of 2006 decreased as a result of lower natural gas prices. Petroleum and natural gas revenue and cash flow for the fourth quarter of 2006 and the first quarter of 2007 increased slightly due to strengthening natural gas prices. Net earnings for the first quarter of 2007 decreased due to an $8.2 million unrealized loss on financial instruments as a result of adopting the new accounting standards for financial instruments and electing not to use hedge accounting. Petroleum and natural gas revenue and cash flow increased in the second quarter of 2007 due to the Corporate Acquisition. For the third quarter of 2007, revenue, cash flow and net earnings decreased as a result of lower natural gas prices but increased for the fourth quarter of 2007 due to strengthening natural gas prices. Net earnings for the fourth quarter of 2007 includes a future income tax charge of $2.1 million due to a reduction in federal income tax rates.

SELECTED ANNUAL INFORMATION

($ thousands, except per unit amounts)	**2007**	2006	2005
Petroleum and natural gas revenue	**382,052**	310,518	375,427
Net earnings	**70,203**	91,598	88,924
Per unit basic	**0.76**	1.23	1.29
Per unit diluted	**0.76**	1.21	1.27
Cash flow	**214,290**	190,329	205,977
Per unit diluted	**2.02**	2.16	2.45
Total assets	**1,563,078**	1,210,704	1,152,985
Distributions declared	**114,142**	125,563	116,460
Working capital deficiency	**25,459**	14,835	22,873
Bank debt	**296,590**	75,000	71,326
Convertible debentures	**122,174**	119,605	79,381
Total debt	**444,223**	209,440	173,580

Distributions

Management monitors the Trust's distribution payout policy with respect to forecasted net cash flow, debt levels and capital expenditures. As a crude oil and natural gas trust, Progress has a declining asset base and therefore relies on ongoing development activities and acquisitions to replace production and add additional reserves. Progress' future crude oil and natural gas production and reserves are highly dependent on its success in exploiting its asset base and acquiring additional reserves. The success of these activities, along with natural gas prices are the main factors influencing the sustainability of the Trust's distributions.

Starting in January 2007, the Trust reduced its monthly distributions from $0.14 per trust unit to $0.10 per trust unit due to a reduction in forecasted 2007 cash flow as a result of the then current weakness in natural gas prices. The distribution reduction reinforces Progress' commitment to sustainability. Progress defines sustainability as maintaining production and reserves per trust unit over an extended period of time. Progress' sustainability objective is to annually retain sufficient cash flow to replace reserves produced. As a result, $114.1 million was distributed in 2007 compared to $125.6 million in 2006. The distributions for 2007 include $1.8 million relating to the performance units that vested on July 2, 2007.

For the year ended December 31, 2007, cash flow from operating activities (after changes in non-cash working capital) of $220.4 million exceeded cash distributions of $114.1 million. This was consistent with 2006 in which cash flow from operating activities (after changes in non-cash working capital) of $190.2 million exceeded cash distributions of $125.6 million.

For the year ended December 31, 2007, cash distributions of $114.1 million exceeded net earnings of $70.2 million. This is consistent with 2006 in which cash distributions of $125.6 million exceeded net earnings of $91.6 million. Net earnings includes significant non-cash charges which in 2007 were $144.8 million that do not impact cash flow. Net earnings also include fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, other non-cash charges such as DD&A are not a good proxy for the cost of maintaining our productive capacity given the natural declines associated with crude oil and natural gas assets. In these instances, where distributions exceed net earnings, a portion of the cash distribution paid to unitholders may represent an economic return of the unitholders' capital.

For 2007, cash distributions and capital spending (excluding the Corporate Acquisition and Wapiti asset purchase described below) combined totaled $251.1 million, which was $30.7 million higher than the cash flow from operating activities (after changes in non-cash working capital) of $220.4 million. For 2006 cash distributions and capital spending exceeded the cash flow from operating activities (after changes in non-cash working capital) by $70.1 million in which monthly distributions were at the $0.14 per unit level. Progress relies on access to capital markets to the extent cash distributions and net capital expenditures exceed cash flow from operations (after changes in non-cash working capital). Over the long term Progress expects to fund distributions and capital expenditures with its cash flow, however, it will continue to fund acquisitions and growth through additional debt and equity. In the crude oil and natural gas sector, because of the nature of reserve reporting, the natural reservoir declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore, maintenance capital is not disclosed separately from development capital spending.

On October 25, 2007 the Alberta government announced the New Royalty Framework ("framework"), which is proposed to take effect on January 1, 2009. Progress has reviewed the information currently provided by the government and believes that the changes to the Alberta royalties may increase Progress' Alberta royalty rate from 27 percent to 31.5 percent based on current production and a realized natural gas price of $7.00 per gj. Using the same production and price assumptions, Progress' royalty rate is estimated to increase marginally from 25 percent to 27.5 percent, on a corporate basis, resulting in an approximate five percent reduction in 2009 cash flow.

Although Progress intends to continue to make cash distributions to unitholders, these distributions are not guaranteed.

Capital Expenditures

The Trust invested approximately $173.4 million in total capital expenditures in 2007 compared to $134.7 million in 2006. Exploration and development capital amounted to $137.0 million in 2007, consistent with 2006 of $133.9 million.

($ thousands)	**2007**	2006
Land acquisitions and retention	**6,186**	11,936
Geological and geophysical	**5,039**	5,892
Drilling and completions	**94,422**	82,611
Equipping and facilities	**30,979**	31,926
Corporate assets	**371**	1,521
Exploration and development capital	**136,997**	133,886
Net property acquisitions (dispositions)	**36,375**	766
Total capital expenditures	**173,372**	134,652

Progress drilled 92 gross wells (47.5 net) with a 95 percent success rate in 2007. Included in this drilling activity was 31 gross wells (22.4 net) drilled in the Deep Basin region of northwest Alberta, 50 gross wells (16.9 net) in the

Foothills region of northeast British Columbia, two gross wells (1.2 net) in the Fort St. John Plains region of northeast British Columbia and 9 gross wells (7.0 net) in central Alberta. Progress began 2007 with an exploration and development capital budget for the year of $110.0 million and increased it to $140.0 million following the Corporate Acquisition. Exploration and development capital expenditures for 2007 of $137.0 million was consistent with the revised $140.0 million budget. The successful 2007 capital program resulted in a proved plus probable finding and development cost of $14.59 per boe before acquisitions and $16.67 per boe including acquisitions.

On May 31, 2007 Progress acquired certain petroleum and natural gas assets from a major producer in the Wapiti area for $41.3 million, net of final closing adjustments. The acquisition added approximately 800 boe per day of production, 1.54 million boe of proved plus probable reserves and 31,000 net undeveloped acres of land with varying working interests which will create further opportunities to consolidate working interests within the region. Progress believes there are substantial upside opportunities on the acquired lands which are contiguous with the Trust's properties in the Gold Creek region. The acquisition also added ownership in infrastructure which is strategic to Progress' area of expansion plans.

In July 2007, Progress sold its gross overriding interest and certain land in the Copton and Cutpick areas of northwest Alberta for $8.0 million.

On November 30, 2007 Progress acquired assets in the Blair and Cameron areas of the Foothills region of British Columbia for $3.6 million.

In June 2006, the Trust disposed of its petroleum and natural gas assets in the Unity, Saskatchewan area to a private company for 2,860,000 common shares valued at $1.20 per share for a total consideration of $3.4 million. As this was a non-cash transaction, it is excluded from the table above.

The 2008 capital investment program will be mainly directed to the Trust's growing positions in the Deep Basin in northwest Alberta and the Foothills regions of northeast British Columbia. Progress expects to drill approximately 50 net wells on an exploration and development capital program totaling between $110 million to $125 million. The Trust's capital investment program is expected to be split approximately 65 percent to drilling and completions, 25 percent to major facilities and 10 percent to land and seismic expenditures. The Trust does not set a budget for property acquisitions.

Undeveloped Land

Undeveloped land at December 31, 2007 increased 50 percent compared to December 31, 2006 due to the Corporate Acquisition, as well as other asset acquisitions and acreage purchased at Crown land sales during 2007. The Trust acquired approximately 240,000 net acres of undeveloped land through the Corporate Acquisition, 31,000 net acres as part of the Wapiti asset acquisition completed May 31, 2007, 8,000 net acres through an asset acquisition completed November 30, 2007 in the Blair and Cameron areas of the Foothills region, and purchased approximately 34,000 net acres at Crown land sales during 2007 in Progress' core regions.

(acres)	**2007 Gross**	**2007 Net**	2006 Gross	2006 Net
Alberta	**394,000**	**293,000**	248,000	203,000
British Columbia	**689,000**	**249,000**	410,000	157,000
Saskatchewan	**4,000**	**3,000**	4,000	3,000
Total undeveloped land	**1,087,000**	**545,000**	662,000	363,000

Over the next 12 months 156,000 net acres or 29 percent of Progress' undeveloped land will be subject to expiry. The Trust has an active capital program and farmout strategy to minimize undeveloped land expires.

Goodwill

The goodwill balance of $414.7 million is primarily the result of the acquisition of Cequel in 2004. In accordance with Canadian GAAP, goodwill is not amortized but is subject to an impairment test. Progress conducts a goodwill impairment test on an annual basis at its fiscal year end. Goodwill may be tested for impairment between annual tests

in certain situations. There was no impairment of goodwill as a result of the tests conducted at December 31, 2007 and 2006.

Liquidity and Capital Resources

($ thousands except per unit amounts)	2007	2006
Working capital deficiency	**25,459**	14,835
Bank debt	**296,590**	75,000
Convertible debentures	**122,174**	119,605
Total debt	**444,223**	209,440
Units outstanding and issuable for exchangeable shares (thousands)	**110,781**	88,114
Market price per unit at end of year	**10.85**	12.57
Market value of trust units and exchangeable shares	**1,201,974**	1,107,593
Cash flow	**214,290**	190,329
Total debt to cash flow ratio	**2.07**	1.10

At December 31, 2007 the Trust had $296.6 million outstanding on its credit facility of $375.0 million, as well as $122.2 million for the debt portion of the Debentures and a working capital deficiency of $25.5 million, resulting in $444.2 million of total debt. The Trust currently has a $340 million extendible revolving term credit facility and a $35 million working capital credit facility with a syndicate of banks. The facilities are available on a revolving basis for a period of at least 364 days until May 27, 2008, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. The credit facilities are secured by a $1 billion fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress Energy Ltd. in respect of the Trust's obligations. The $375 million borrowing base is subject to semi-annual review by the banks.

Bank debt of $296.6 million as at December 31, 2007 was higher than the December 31, 2006 bank debt of $75.0 million due to the Corporate Acquisition, as well as the capital program and asset acquisitions completed in 2007. Working capital deficiency increased from $14.0 million as at December 31, 2006 to $25.5 million as at December 31, 2007 as a result of an increase in accounts payable and accrued liabilities due to the timing of invoice payments and less cash on hand.

On April 2, 2007 Progress purchased all of the issued and outstanding shares of a private company (refer to Corporate Acquisition above) and in conjunction with the purchase, sold certain assets of the private company to ProEx. The net cash consideration of $393.0 million, was financed by the issuance of 21,000,000 trust units at a price of $12.00 per trust unit for proceeds of $252.0 million ($238.7 million net of issue costs) and through increased bank debt.

On August 22, 2006 the Trust issued $75.0 million principal amount of 6.25 percent convertible unsecured subordinated debentures for net proceeds of $71.7 million. The 6.25 percent debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $19.50 per trust unit. The 6.25 percent debentures mature on September 30, 2011 at which time they become due and payable. Interest and principal repayments may be made by way of cash or trust units. The net proceeds were used to reduce outstanding bank indebtedness.

The 6.75 percent convertible unsecured subordinated debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $15.00 per trust unit. The 6.75 percent debentures mature on June 30, 2010 at which time they are due and payable. The Trust may elect to satisfy the interest and principal obligations by the issuance of trust units. The net proceeds were used to reduce outstanding bank indebtedness.

The Debentures have been classified as debt net of the fair value of the conversion feature which has been classified as part of unitholders' equity and net of issue costs. For the 6.25 percent debentures, this resulted in $66.7 million being classified as debt and $4.9 million being classified as equity. For the 6.75 percent debentures, $90.5 million was originally classified as debt and $4.9 million was classified as equity. Issue costs are amortized over the term of the Debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed within interest and financing expense on the consolidated statements of earnings.

The following table outlines the Debenture activity for the years ended December 31, 2007 and 2006:

	2007			2006		
($ thousands)	6.75%	6.25%	**Total**	6.75%	6.25%	Total
Principal, beginning of year[1]	55,727	75,000	**130,727**	86,182	75,000	161,182
Converted to trust units	-	-	**-**	(30,455)	-	(30,455)
Principal, end of year	55,727	75,000	**130,727**	55,727	75,000	130,727
Debt portion, beginning of year[1]	52,300	67,305	**119,605**	79,381	66,748	146,129
Accretion	508	945	**1,453**	535	337	872
Amortization of issue costs	466	650	**1,116**	497	220	717
Conversions to trust units[2]	-	-	**-**	(28,113)	-	(28,113)
Debt portion, end of year	53,274	68,900	**122,174**	52,300	67,305	119,605
Equity portion, beginning of year[1]	2,756	4,946	**7,702**	4,261	4,946	9,207
Conversions to trust units	-	-	**-**	(1,505)	-	(1,505)
Equity portion, end of year	2,756	4,946	**7,702**	2,756	4,946	7,702

(1) The 6.75 percent debentures were issued February 2, 2005 and the 6.25 percent debentures were issued August 22, 2006.
(2) Net of unamortized issue costs.

The Trust's investing activities for 2007 consisted of the Corporate Acquisition as well as expenditures on the capital program and asset acquisitions. Management anticipates that the Trust will continue to have adequate liquidity to fund future working capital and forecasted capital expenditures during 2008 through a combination of cash flow and debt. Cash flow used to finance these commitments may reduce the amount of cash distributions paid to unitholders.

Outstanding as at February 27, 2008 were 97,817,443 trust units, 8,941,859 exchangeable shares and $130.7 million of Debentures convertible into 7,561,287 trust units.

Off Balance Sheet Arrangements

The Trust has no guarantees or off-balance sheet arrangements except for certain lease agreements, and letters of credit. The Trust has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases on the balance sheet as at December 31, 2007. The total future obligation from these operating leases is described below in the section "Contractual Obligations and Commitments".

Letters of credit of approximately $1.7 million as at December 31, 2007 (2006 – $1.4 million) have been issued in the normal course of business mainly for contract firm transportation.

Unitholders' Equity

At December 31, 2007, there were 97.5 million trust units outstanding, a 29 percent increase from the 75.5 million trust units outstanding at December 31, 2006. The increase in the number of trust units is the result of 21.0 million trust units issued to finance a portion of the Corporate Acquisition (gross proceeds of $252.0 million, $238.7 million net of issue costs), 0.6 million units issued ($7.1 million) on the conversion of exchangeable shares during 2007 and 0.4 million trust units issued ($5.1 million) to settle the performance units that vested on July 2, 2007.

Contractual Obligations and Commitments

The Trust contracts for firm transportation on the TransCanada and Atco systems in Alberta and the Spectra Energy system in British Columbia. The Trust has an office lease commitment that extends to 2009. Annual costs of this lease commitment, which include rent and operating expenses, amount to approximately $1.5 million.

The Trust must pay crown royalty, surface rentals, mineral taxes and abandonment and reclamation costs with respect to its ongoing ownership of hydrocarbon production rights. The amounts paid with respect to these burdens will depend on the future ownership, production, prices and legislative environment at the time.

Production of 4,100 mcf per day is dedicated to certain aggregator sales arrangements. Under these arrangements, Progress receives a price based on the average netback price of the pool, net of transportation expenses incurred by the aggregator.

		Minimum Annual Commitment				
($ thousands)	Total	2008	2009	2010	2011	2012
Bank debt (1)	296,590	-	296,590	-	-	-
Convertible debentures	130,727	-	-	55,727	75,000	-
Pipeline commitments	48,284	14,623	13,578	11,006	7,757	1,320
Drilling rig commitments	1,779	1,779	-	-	-	-
Operating leases	272	272	-	-	-	-
Financial instrument premiums	4,622	4,622	-	-	-	-
Farm-in	820	820	-	-	-	-
Office lease	2,712	1,479	1,233	-	-	-
Total	485,806	23,595	311,401	66,733	82,757	1,320

(1) Based on the existing terms of the revolving credit facilities which are subject to renewal on or before May 27, 2008. If not extended, the facilities would be available on a non-revolving basis for a one-year term at which time the facilities would be due and payable.

FOURTH QUARTER ANALYSIS

	Q4 2007	Q3 2007	Q4 2006
OPERATIONAL HIGHLIGHTS			
Daily Production			
Natural gas *(mcf/d)*	**123,740**	120,804	88,568
Crude oil *(bbls/d)*	**2,068**	2,268	2,030
Natural gas liquids *(bbls/d)*	**1,548**	1,370	1,269
Total daily production *(boe/d)*	**24,240**	23,772	18,060
Average Benchmark Prices			
Natural gas - AECO (daily) *($/gj)*	**5.82**	4.88	6.54
Natural gas - AECO (monthly) *($/gj)*	**5.69**	5.32	6.03
Natural gas - Station #2 (daily) *($/gj)*	**5.95**	4.94	6.37
Crude oil - WTI *(US$/bbl)*	**90.69**	75.38	60.21
Crude oil - Edmonton par price *(Cdn$/bbl)*	**85.35**	79.84	64.53
Exchange rate *(US$/Cdn$)*	**0.9818**	1.0446	1.1393
Average Realized Prices			
Natural gas - ($/mcf)	**6.49**	5.77	7.05
Crude oil ($/bbl)	**81.67**	78.77	59.26
Natural gas liquids ($/bbl)	**71.51**	62.91	55.71
FINANCIAL HIGHLIGHTS			
($ thousands, except per unit amounts)			
Petroleum and natural gas revenue	**99,592**	88,480	75,183
Royalties	**(21,267)**	(19,242)	(17,089)
Realized gain on financial instruments	**2,551**	6,324	10,451
Operating expenses	**(13,184)**	(14,596)	(11,013)
Transportation expenses	**(4,152)**	(4,295)	(2,593)
General and administrative expenses	**(2,022)**	(2,454)	(1,548)
Unit based compensation expense	**(2,594)**	(2,394)	(1,496)
Cash flow	**54,727**	48,085	49,603
Depletion, depreciation and accretion	**(37,235)**	(37,345)	(24,542)
Net earnings	**9,922**	11,909	21,538
Per unit basic	**0.10**	0.12	0.29
Per unit diluted	**0.10**	0.12	0.28
Exploration and development capital	**47,210**	31,726	35,475
Net property acquisitions (dispositions)	**3,295**	(8,293)	(171)
Total capital expenditures	**50,505**	23,433	35,304

Production

Production during the fourth quarter (the "Quarter") of 2007 of 24,240 boe per day was slightly higher than the third quarter of 2007 of 23,772 boe per day and was 34 percent higher than the fourth quarter of 2006 at 18,060 boe per day. The production increase from the third quarter to the fourth quarter in 2007 was primarily the result of new wells brought on production during the Quarter. The increase in production for the Quarter over the fourth quarter of 2006 was due to the Corporate Acquisition completed on April 2, 2007 as well as new wells brought on production.

Revenue

Petroleum and natural gas revenue for the Quarter of $99.6 million was 13 percent higher than the third quarter of 2007 of $88.5 million and was 32 percent higher than the $75.2 million recognized for the fourth quarter of 2006. The increase from the third quarter of 2007 was primarily the result of higher natural gas prices, while the increase from the fourth quarter of 2006 was due to increased production, primarily from the Corporate Acquisition.

Royalties

Royalties for the Quarter of $21.3 million was 11 percent higher than the third quarter of 2007 of $19.2 million and was 24 percent higher than the fourth quarter of 2006 of $17.1 million due to higher revenues. The average royalty rate for the Quarter of 21.4 percent was consistent with the third quarter of 2007 and the fourth quarter of 2006 of 21.7 percent and 22.7 percent, respectively.

Operating Expenses

Operating expenses for the Quarter of $13.2 million were 10 percent lower than the third quarter of 2007 of $14.6 million and 20 percent higher than the fourth quarter of 2006 of $11.0 million. The decrease from the third quarter of 2007 was due to operating efficiencies realized on the assets acquired in the Corporate Acquisition. The increase from the fourth quarter of 2006 was due to increased production as a result of the Corporate Acquisition. Operating expenses during the Quarter averaged $5.91 per boe compared to $6.67 per boe during the third quarter of 2007 and $6.63 per boe during the fourth quarter of 2006. The lower operating expenses per boe are the result of efficiencies obtained on the assets acquired in the Corporate Acquisition.

Transportation Expenses

Transportation expenses for the Quarter of $4.2 million were consistent with the third quarter of 2007 of $4.3 million and 60 percent higher than the fourth quarter of 2006 of $2.6 million. The increase from the fourth quarter of 2006 was due to the increased production as a result of the Corporate Acquisition. Transportation expenses during the Quarter averaged $1.86 per boe compared to $1.96 per boe during the third quarter of 2007 and $1.56 per boe during the fourth quarter of 2006. The increase from the fourth quarter of 2006 was due to higher transportation and treatment tolls associated with the Corporate Acquisition including higher treatment tolls associated with the Slave Point production at the Bubbles property. Approximately 40 percent of the Trust's production was in British Columbia where there is an infrastructure owned by Spectra Energy that enables gas producers to avoid facility construction in exchange for gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

General and Administrative Expenses

G&A expenses for the Quarter of $2.0 million were 18 percent lower than the third quarter of 2007 of $2.5 million and were 31 percent higher than the fourth quarter of 2006 of $1.5 million. The decrease from the third quarter of 2007 was due to higher recoveries during the Quarter as a result of higher capital spending. The increase from the fourth quarter of 2006 was due to the increased size of the Trust as well as higher costs incurred to retain employees. G&A expenses averaged $0.91 per boe during the Quarter compared to $1.12 in the third quarter of 2007 and $0.93 during the fourth quarter of 2006.

Depletion, Depreciation and Accretion

DD&A expense for the Quarter of $37.2 million was consistent with the third quarter of 2007 of $37.3 million and 52 percent higher than the fourth quarter of 2006 of $24.5 million. The increase over the fourth quarter of 2006 was due to the Corporate Acquisition. This resulted in DD&A of $16.70 per boe for the Quarter compared to $17.08 per boe for the third quarter of 2007 and $14.77 for the fourth quarter of 2006.

Future Income Taxes

The provision for future income taxes in the Quarter resulted in a charge of $1.7 million compared to a recovery for the third quarter of 2007 of $5.9 million and a recovery for the fourth quarter of 2006 of $1.4 million. The provision for the Quarter includes a charge of $2.1 million as a result of lower federal income tax rates enacted during the Quarter which reduced the value of the Trust's future income tax asset.

Net Earnings and Cash Flow

Net earnings for the Quarter were $9.9 million compared to $11.9 million for the third quarter of 2007 and $21.5 million for the fourth quarter of 2006. The decrease in net earnings from the fourth quarter of 2006 was due to a higher DD&A expense, as well as, increases to operating, transportation and interest expenses as a result of the Corporate Acquisition.

Cash flow for the Quarter of $54.7 million was 14 percent higher than the third quarter of 2007 of $48.1 million and 10 percent higher than the fourth quarter of 2006 of $49.6 million. The increase over the third quarter of 2007 was due higher commodity prices and the increase over the fourth quarter of 2006 was due to increased production as a result of the Corporate Acquisition and successful drilling.

Capital Expenditures

During the Quarter, the Trust incurred $50.5 million of capital expenditures comprised of $1.8 million in land acquisition and retention, $1.7 million in geological and geophysical, $36.0 million in drilling and completions, $7.7 million in facility construction, and $3.3 million on property acquisitions (dispositions). During the Quarter the Trust drilled 39 gross wells (20.1 net) with 26 gross wells (9.9 net) drilled in the northeast British Columbia Foothills, seven gross wells (5.5 net) drilled in the Deep Basin of northwest Alberta and six gross wells (4.7 net) drilled in central Alberta. The $3.3 million in net property acquisitions (dispositions) includes an asset acquisition completed on November 30, 2007 in the Blair and Cameron areas of the Foothills region for $3.6 million. In the third quarter of 2007, Progress sold its gross overriding interest and certain land in the Copton and Cutpick areas of northwest Alberta for $8.0 million.

Total capital investment during the Quarter was $50.5 million compared to $23.4 million in the third quarter of 2007 and $35.3 million in the fourth quarter of 2006.

ENVIRONMENT, HEALTH AND SAFETY

Progress places a high priority on preserving the quality of its environment and protecting the health and safety of its employees, contractors and the public in communities in which it lives and works. Progress actively participates in industry-recognized programs at the highest possible levels in an effort to support continuous improvement.

Progress is committed to meeting its responsibilities to protect the environment through a variety of programs and actively monitoring its compliance with all regulators. Progress strives to employ capital and energy efficient methods to minimize its footprint and maximize the recovery of its resources. Progress has progressed from a "Bronze" level upon the formation of the Trust in 2004 to in 2007 achieving the Canadian Association of Petroleum Producers ("CAAP") highest level, "Platinum". Platinum stewardship means that Progress has demonstrated by audit and by statistics that its safety & environment management system has good sound effective leadership and performance in the areas of health, safety, environment and social responsibility.

Progress participates in the Environment, Health and Safety Stewardship Program developed by CAAP. Progress' participation requires its commitment to continuous improvement in its environment, health and safety ("EHS") management practices including sound planning and implementation, open communication and demonstrated performance and a thorough external audit of its activities at least once every 3 years. Progress also conducted a company wide EH&S Management System audit in 2007. An action plan was spawned that included Safety Leadership Training for Supervisors; Hazard Assessment Training for Operators and Supervisors; the development of site specific work procedures and the development of policies outlining Social Responsibility.

Progress continually works to improve its health and safety performance through increased awareness in the field by frequently communicating safety responsibilities to our employees and contractors and by issuing and sharing safety information. Health and safety is increasingly more visible in the field and Progress is becoming more active with contractor safety management through industry committee participation and the promotion of industry recognized best practices.

In 2007, Progress' overall health and safety performance was consistent in 2007 compared to 2006. There was no employee lost time incidents in 2007 or 2006. There were a total of 34 recorded contractor injury incidents in 2007 compared to 37 contractor incidents in 2006. Progress' contractors had 9 lost-time incidents in 2007 compared to 8 in 2006.

Progress is committed to environmental stewardship and the health and safety of its employees, contractors and the general public in the communities in which it operates.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with Canadian GAAP requires Management to make judgments and estimates that affect the financial results of the Trust. Progress' Management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. A summary of significant accounting policies are presented in Note 1 to the consolidated financial statements. The critical estimates are discussed below:

Petroleum and Natural Gas Reserves

All of Progress' petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The evaluation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

On October 25, 2007 the Alberta government announced the New Royalty Framework ("framework"), which is proposed to take effect on January 1, 2009. As the new framework has yet to become law, and all of the details have not been readily available, the reserves as at December 31, 2007 do not include the impact of this proposed framework. Progress has reviewed the information currently provided by the government and believes that the changes to the Alberta royalties may increase Progress' Alberta royalty rate from 27 percent to 31.5 percent based on current production and a realized natural gas price of $7.00 per gj. Using the same production and price assumptions, Progress' royalty rate is estimated to increase marginally from 25 percent to 27.5 percent, on a corporate basis. The impact of the royalty increase is a decrease to the net present value of the Trust's reserves by approximately one to two percent when using a 10 percent discount rate and using GLJ forecast prices as at January 1, 2008.

Depletion Expense

The Trust uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation expense.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery

ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion expense.

Asset Retirement Obligations

The asset retirement obligations is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

New legislation passed in June 2007, effective January 1, 2011, will apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and will treat such distributions as dividends to the unitholders.

CHANGE IN ACCOUNTING POLICIES AND RECENT ACCOUNTING PRONOUNCEMENTS

Internal Control Reporting

In March 2006 Canadian Securities Administrators decided to not proceed with proposed multilateral instrument 52-111 Reporting on Internal Control over Financial Reporting and instead proposed to expand multilateral instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. The major changes resulting from this is the CEO and CFO will be required to certify in the annual certificates that they have evaluated the effectiveness of internal controls over financial reporting ("ICOFR") as of the end of the financial year and disclose in the annual MD&A their conclusions about the effectiveness of ICOFR. There will be no requirement to obtain an internal control audit opinion from the issuer's auditors concerning management's assessment of the effectiveness of ICOFR. There is also no requirement to design and evaluate internal controls against an external control framework. This proposed amendment is expected to apply for the year ended December 31, 2008. Progress is continuing with its evaluation of ICOFR to ensure it meets the criteria for the proposed certification for December 31, 2008.

Financial Instruments

On January 1, 2007 the Trust adopted the new accounting standards regarding the accounting for financial instruments. In addition to the adoption of the new standards, Management elected not to use hedge accounting and therefore, records the fair value of its natural gas financial contracts at each reporting period with the change in the fair value being classified as unrealized gains or losses on the statement of earnings. The accounting for hedging relationships for prior fiscal periods are not retroactively changed, therefore, there was no restatement of the financial position or results of operation as at and for the year ended December 31, 2006.

On January 1, 2007 the fair value of the commodity price contracts was an asset of $15.6 million and resulted in an increase to accumulated other comprehensive income and the future income tax liability of $10.5 million and $5.1 million, respectively. The $10.5 million recognized in accumulated other comprehensive income was amortized over the term of the contracts through other comprehensive income with a corresponding unrealized gain on financial instruments on the statement of earnings. As a result, for the year ended December 31, 2007 $10.5 million, net of tax, was charged to other comprehensive income with a corresponding unrealized gain on financial instruments of $15.6 million and a charge to future income tax expense of $5.1 million. The unrealized gain of $15.6 million was offset by the change in fair value from January 1, 2007 of $15.6 million resulting in an unrealized gain of nil for 2007.

Effective December 31, 2007 Progress early adopted the disclosures required under section 3862 Financial Instruments – Disclosures which applies to both recognized and unrecognized financial instruments. These disclosures, which

include the nature and extent of risks arising from financial instruments, are included in note 11 of the audited consolidated financial statements

Capital Disclosures

Effective December 31, 2007 Progress early adopted the new recommendations of the CICA for disclosure of the Company's objectives, policies and processes for managing capital (Section 1535) as discussed in note 8 of the audited consolidated financial statements.

Convergence with International Reporting Standards

On February 13, 2008, Canada's Accounting Standards Board confirmed January 1, 2011 as the effective date for the convergence of Canadian GAAP to International Financial Reporting Standards. The Canadian Securities Administrators are in the process of examining changes to securities rules as a result of this initiative. As this change initiative is in its infancy, Progress has not determined its impact on its financial position or results of operations.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's Management, as appropriate, to allow timely decisions regarding required disclosures. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings that the Trust's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Trust. It should be noted that while the Trust's Chief Executive Officer and Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

RISK FACTORS AND RISK MANAGEMENT

Investors that purchase trust units are participating in the net cash flow from a portfolio of natural gas and crude oil producing properties. As such, the cash flow paid to investors and the value of Progress' units is subject to numerous risk factors. Some of the risks are common to all businesses while many are associated with the oil and gas industry. The following information is only a summary of certain risk factors which could affect the Trust's future results:

Commodity Price Risk

The Trust's results of operations and financial condition are dependent on prices received for the production of natural gas and crude oil. With the Trust's production heavily weighted to natural gas, changes to natural gas prices have the most material effect on its cash flow. Prices for natural gas and crude oil have fluctuated significantly during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil producing regions, which are beyond the control of the Trust. Prices received from production in Canada also reflect changes in the Canadian/US currency exchange rate. Any decline in the prices for natural gas and crude oil could have a material adverse effect on the Trust's operations, financial condition and the level of capital expenditures provided for the development of its natural gas and crude oil reserves.

Progress uses financial derivative instruments in an effort to limit a portion of the potential adverse effects resulting from volatility in natural gas and crude oil commodity prices, while retaining exposure to upside price movements. The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. To the extent commodity price exposure is hedged, the benefits that would otherwise be experienced if commodity prices were to increase would be foregone.

Operational Matters

The ownership and operation of oil and natural gas wells, pipelines and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to the Trust's natural gas and oil properties and assets, as well as possible liability to third parties. The Trust may become liable for damages arising from such events against which it cannot insure or against which it

may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the cash flow of Progress.

Progress employs prudent risk management practices and maintains suitable liability insurance, where available. Business interruption insurance is also purchased for selected facilities, to the extent that such insurance is reasonably available.

Reserve Estimates

Estimates of economically recoverable natural gas and crude oil reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating expenses. All of these estimates may vary from actual results. Estimates of the recoverable natural gas and crude oil reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Trust's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

On October 25, 2007 the Alberta government announced the New Royalty Framework ("framework") which is proposed to take effect on January 1, 2009. The framework proposes a new simplified royalty formula for natural gas that will operate on a sliding scale determined by commodity prices, well productivity and drilling depth. The impact of the royalty increase is a decrease to the net present value of the Trust's reserves by approximately one to two percent when using a 10 percent discount rate and using GLJ forecast prices as at January 1, 2008.

Each year, a firm of independent engineers evaluates a significant portion of proved and probable reserves. At December 31, 2007, 100 percent of the reserves were evaluated by GLJ.

Exploration and Development Risks

Oil and gas exploration and development requires manpower and capital to generate, develop and test exploration concepts. The eventual testing of a concept will not necessarily result in the discovery of economical reserves.

Progress attempts to minimize the risk of developing existing and new reserves by ensuring that: (a) the majority of prospects have multi-zone potential (b) activity is focused in core regions where expertise and experience is greatest (c) the number of wells drilled is large enough to increase the probability of statistical success rates (d) geophysical techniques are utilized where appropriate (e) by focusing its activities in core regions and major play types, allowing it to leverage off its experience and knowledge in these areas further aiding efficiencies and (f) farm-outs are entered into to minimize risk on plays it considers higher risk.

Access to Capital Markets

The Trust distributes the majority of its cash flow to unitholders. Access to equity and debt markets may be required for the Trust to finance acquisition and development activity to maintain and grow value to unitholders. Debt and equity markets may not be available when required

Progress' trust units are listed on the TSX and the Trust maintains an active investor relations program designed to facilitate access to the equity capital markets. Progress also maintains a prudent capital structure by retaining a portion of its net cash flow for debt repayment when appropriate, managing capital expenditures within rate of return risk parameters and by utilizing equity markets.

Regulatory Risk

There can be no assurance that government royalties, income tax laws, environmental laws and regulatory requirements relating to the oil and gas industry, such as the status of mutual fund trusts, will not be changed in a manner which adversely affects the Trust or its unitholders. For example, the tax efficiency of Progress is contingent upon its status as a mutual fund trust under Canadian tax law and therefore may be subject to unanticipated legislative and/or regulator modification.

Although the Trust has no control over these regulatory risks, Progress continuously monitors changes in these areas by participating in industry organizations and conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on the Trust's financial and operating results.

Proposed Changes to the Alberta Royalty Regime

On October 25, 2007 the Alberta government announced the New Royalty Framework ("framework") which is proposed to take effect on January 1, 2009. The framework proposes a new simplified royalty formula for natural gas that will operate on a sliding scale determined by commodity prices, well productivity and drilling depth.

Progress has reviewed the information currently provided by the government and believes that the change to the Alberta royalties may increase Progress' Alberta royalty rate from 27% to 31.5% based on current production and a realized natural gas price of $7.00 per GJ. On a corporate basis, using the same production and price assumptions, Progress' royalty rate on a corporate basis is estimated to increase marginally from 25% to 27.5% resulting in an approximate five percent reduction in 2009 cash flow. The new framework has not yet been passed into law and Progress continues to monitor its status.

Environment and Safety Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Progress to incur costs to remedy such discharge. Although Progress believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Progress's financial condition, results of operations or prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of Progress. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on Progress and its operations and financial condition.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Progress's exploration and production facilities and other operations and activities emit greenhouse gases which will likely subject Progress to possible future legislation regulating emissions of greenhouse gases, such as the government of Canada's proposed *Clean Air Act* of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act*. The direct or indirect costs of these regulations may adversely affect the expected business of the Progress.

The board of directors has reviewed and approved policies and procedures covering environmental risks, emergency response and employee safety. These policies and procedures are designed to protect and maintain the environment with respect to all corporate operations on behalf of unitholders, employees and the public at large. The Trust mitigates environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations and maintaining adequate insurance.

Credit Risks

The Trust assumes customer credit risk associated with natural gas and crude oil sales, financial hedging transactions and joint venture participants

Management has established controls designed to mitigate the risk of default or non-payment with respect to natural gas and crude oil sales, financial hedging transactions and joint venture participants.

Income Tax Matters

New legislation passed in June 2007, will apply a tax ("SIFT tax") at the trust level on distributions of certain income from trusts, such as the Trust, at rates of tax comparable to the combined federal and provincial corporate tax and will treat such distributions as dividends to the unitholders. The SIFT tax results in adverse tax consequences to the Trust and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact cash distributions from the Trust.

Generally, there will be a four year transition period for an existing trust, such as the Trust, and the tax under the new legislation will not apply until January 1, 2011. However, the new legislation provides that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded.

"Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a SIFT trust's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of the SIFT's issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. For Progress the growth limits are $476.8 million for 2007 (less $252.0 million as a result of the equity offering in regards to the Corporate Acquisition) and $238.4 million for each of 2008, 2009 and 2010 with any unused amount rolling forward to the next year.

While the normal growth restrictions are such that it is unlikely they would affect the Trust's ability to raise the capital required to maintain and grow its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions. The SIFT tax has reduced the value of the Trust Units, which has increased the cost to the Trust of raising capital in the public capital markets. In addition management of Progress Energy believes that the SIFT tax: (a) substantially eliminates the competitive advantage that the Trust and other Canadian energy trusts enjoyed relative to their corporate peers in raising capital in a tax-efficient manner, and (b) places the Trust and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including US master limited partnerships, which will continue to not be subject to entity level taxation. The new legislation also makes the Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for the Trust to compete effectively for acquisition opportunities. There can be no assurance that the Trust will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the SIFT tax.

No assurance can be provided that the SIFT tax will not apply to the Trust prior to January 1, 2011, or that the legislation will not be further changed in a manner which affects the Trust and its Unitholders.

Currently, the SIFT Rules provide that the SIFT Tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined SIFT tax rate of 29.5% in 2011.

On February 26, 2008, the Minister of Finance announced (the "**Provincial SIFT Tax Proposal**") that instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will instead be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, the Trust's taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of the Trust's taxable distributions for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and

- that proportion of the Trust's taxable distributions for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal the Trust would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in an effective SIFT Tax rate of 26.5% in 2011 and 25% in 2012. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

Progress will be subject to a Federal income tax on distributions commencing on January 1, 2011. We ended 2007 with $1.2 billion in tax pools with the majority comprising 100 percent deductible exploration expenses. These tax pools provide substantial sheltering of income well beyond 2010 when the taxation of trusts occurs. As we move toward 2011, Progress will benefit from the recently announced combined federal and provincial proposed tax rate reductions from the current level of 31.5 percent to 25 percent in 2012, the lowest expected corporate rate in Canada. Management continues to analyze its business options for structural changes and is working closely with legal and business advisors to determine a course of action and potential restructuring to maximize value in the best interest of unitholders.

Investment Eligibility; Mutual Fund Trust Status

It is intended that the Trust qualify at all times as a mutual fund trust for the purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirement for the maintenance of mutual fund trust status, especially in light of the SIFT tax. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

(a) the Units would cease to be a qualified investment for trusts governed by Exempt Plans. Where, at the end of a month, an Exempt Plan holds Units that ceased to be a qualified investment, the Exempt Plan, must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Units at the time such Units were acquired by the Exempt Plan. In addition, trusts governed by a registered retirement savings plan ("RRSP") or a registered retirement investment fund ("RRIF") which hold Units that are not qualified investments will be subject to tax on the income attributable to the Units while they are non qualified investments, including the full capital gains, if any, realized on the disposition of such Units. Where a trust governed by a RRSP or a RRIF acquires Units that are not qualified investments, the value of the investment will be included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Units that are not qualified investments can have their registration revoked by the CRA;

(b) the Trust would be required to pay a tax under Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unitholders, including non resident persons and residents of Canada who are exempt from Part I tax;

(c) the Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws; and

(d) Units would become taxable Canadian property. As a result, non-resident Unitholders would be subject to Canadian income tax on any gains realized on a disposition of Units held by them.

The Trust may take certain measures in the future to the extent the Trust believes such measures are necessary to ensure the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain unitholders.

OUTLOOK AND 2008 FORECAST

Progress will continue to pursue a disciplined approach to long term sustainability on a per unit basis. Our technical approach and cost control will be primary contributors to sustained value creation for unitholders. Internally generated opportunities will be drilled at a more modest pace than when we were an aggressive growth company. At our current capital investment pace, our inventory of drilling locations currently supports more than three years of activity, while our over 540,000 net acres of undeveloped land provides the opportunity for our technical team to create incremental value.

In creating our Trust, we ensured that we would have access to strong technical and financial staff by having all employees invest in Progress. This creates strong alignment with our unitholders and ensures that we have the professionals to execute our business plan. Employees, Management and Directors hold an 11 percent direct ownership interest in our Trust.

The following table summarizes the Trust's 2008 forecast provided throughout the MD&A. Progress does not forecast commodity prices and as a result, the Trust does not provide a forecast of future cash distributions to unitholders.

2008 Forecast	**Target**
Average annual production	23,500 boe/d
Royalty rate	23 to 24 percent
Operating expenses	$6.50 to $6.75 per boe
G&A expenses	$1.00 to $1.10 per boe
Unit based compensation expenses	$1.10 per boe
Capital expenditures	$110 to $125 million
Drilling activity	50 net wells

ADDITIONAL INFORMATION

Additional information regarding the Trust and its business and operations, including the annual information form ("AIF") is available on the Trust's company profiles at www.sedar.com. Copies of the AIF can also be obtained by contacting the Trust at Progress Energy Trust 1200, 205 – 5th Avenue S.W., Calgary, Alberta, Canada T2P 2V7 or by e-mail at ir@progressenergy.com. This information is also accessible on the Trust's web site at www.progressenergy.com

Progress Energy Trust

Financial Statements and Notes

REPORT OF MANAGEMENT

The accompanying consolidated financial statements of Progress Energy Trust and all the information in this annual report are the responsibility of Management and have been approved by the Trust's Board of Directors.

The financial statements have been prepared by Management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, Management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Progress Energy Trust maintains appropriate systems of internal accounting and administrative controls of high quality. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Trust's assets are properly accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee of the Board of Directors, composed entirely of independent directors, meets regularly with Management, as well as the external auditors, to discuss auditing (external and joint venture), internal controls, accounting policy and financial reporting matters. The Committee reviews the financial statements and Management's Discussion and Analysis and recommends their approval to the Board of Directors. The Committee also considers, for review by the Board and approval by the unitholders, the engagement or re-appointment of the external auditors.

The financial statements have been audited by KPMG LLP, the external auditors, in accordance with Canadian generally accepted auditing standards on behalf of the unitholders. KPMG LLP has full and free access to the Audit Committee.

(signed) "*Michael R. Culbert*"
President and CEO
Progress Energy Ltd.

(signed) "*Art A. MacNichol*"
Vice President, Finance and CFO
Progress Energy Ltd.

February 28, 2008

AUDITORS' REPORT

To the Unitholders of Progress Energy Trust

We have audited the consolidated balance sheets of Progress Energy Trust as at December 31, 2007 and 2006 and the consolidated statements of earnings, comprehensive income and deficit and cash flows for the years ended December 31, 2007 and 2006. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatements. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years ended December 31, 2007 and 2006 in accordance with Canadian generally accepted accounting principles.

Calgary, Canada
February 28, 2008

(signed) "*KPMG LLP*"
Chartered Accountants

PROGRESS ENERGY TRUST
CONSOLIDATED BALANCE SHEETS

As at December 31 ($ thousands)	**2007**	2006
ASSETS		
Current		
Cash and short-term investments	**-**	8,265
Accounts receivable	**47,505**	35,555
Prepaid expenses and deposits	**9,148**	7,798
	56,653	51,618
Property, plant and equipment *(Note 3)*	**1,055,054**	744,431
Future income taxes *(Notes 2 and 9)*	**36,716**	-
Goodwill	**414,655**	414,655
	1,563,078	1,210,704
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**67,127**	50,696
Cash distributions payable	**9,748**	10,564
Current income taxes payable	**5,237**	5,193
	82,112	66,453
Bank debt *(Note 4)*	**296,590**	75,000
Convertible debentures *(Note 5)*	**122,174**	119,605
Asset retirement obligations *(Note 6)*	**35,012**	24,148
Future income taxes *(Note 9)*	**-**	114,367
	535,888	399,573
NON-CONTROLLING INTEREST		
Exchangeable shares *(Note 7)*	**126,384**	122,592
UNITHOLDERS' EQUITY		
Unitholders' capital *(Note 8)*	**990,946**	739,998
Convertible debentures *(Note 5)*	**7,702**	7,702
Contributed surplus *(Note 8)*	**14,468**	9,210
Deficit	**(112,310)**	(68,371)
	900,806	688,539
Commitments *(Note 12)*		
	1,563,078	1,210,704

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board of Directors of Progress Energy Ltd.

(signed) "*David D. Johnson*"
Director

(signed) "*Donald F. Archibald*"
Director

PROGRESS ENERGY TRUST
CONSOLIDATED STATEMENTS OF EARNINGS, COMPREHENSIVE INCOME AND DEFICIT

Year ended December 31 ($ thousands, except per unit amounts)	**2007**	2006
REVENUE		
Petroleum and natural gas	**382,052**	310,518
Royalties	**(84,434)**	(78,762)
	297,618	231,756
Realized gain on financial instruments *(Note 11)*	**16,055**	29,937
Other income	**219**	-
	313,892	261,693
EXPENSES		
Operating	**53,661**	40,353
Transportation	**15,395**	11,017
General and administrative	**8,756**	6,321
Unit based compensation *(Note 8)*	**9,037**	4,874
Interest and financing	**23,015**	11,798
Depletion, depreciation and accretion	**138,636**	94,708
	248,500	169,071
Earnings before taxes and non-controlling interest	**65,392**	92,622
TAXES		
Capital taxes	**126**	180
Future income taxes *(Note 9)*	**(14,861)**	(14,673)
	(14,735)	(14,493)
Net earnings before non-controlling interest	**80,127**	107,115
Non-controlling interest – exchangeable shares *(Note 7)*	**(9,924)**	(15,517)
NET EARNINGS	**70,203**	91,598
OTHER COMPREHENSIVE INCOME		
Amortization of fair value of financial instruments *(Notes 1 and 8)*	**(10,543)**	-
COMPREHENSIVE INCOME	**59,660**	91,598
Deficit, beginning of year	**(68,371)**	(34,406)
Distributions	**(114,142)**	(125,563)
Deficit, end of year	**(112,310)**	(68,371)
NET EARNINGS PER UNIT *(Note 8)*		
Basic	**$0.76**	$1.23
Diluted	**$0.76**	$1.21

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 ($ thousands)	**2007**	2006
Operating Activities		
Net earnings	**70,203**	91,598
Depletion, depreciation and accretion	**138,636**	94,708
Non-controlling interest – exchangeable shares *(Note 7)*	**9,924**	15,517
Convertible debentures accretion *(Note 5)*	**1,453**	872
Amortization of convertible debenture issue costs *(Note 5)*	**1,116**	717
Amortization of commodity sales contract	**(505)**	(570)
Unit based compensation *(Note 8)*	**9,037**	4,874
Asset retirement expenditures *(Note 6)*	**(713)**	(2,714)
Future income taxes	**(14,861)**	(14,673)
	214,290	190,329
Changes in non-cash working capital *(Note 10)*	**6,139**	(170)
	220,429	190,159
Financing Activities		
Increase in bank debt	**212,467**	3,674
Issue of units *(Notes 2 and 8)*	**252,000**	-
Unit issue costs *(Notes 2 and 8)*	**(13,304)**	-
Issue of convertible debentures *(Note 5)*	**-**	75,000
Convertible debenture issue costs *(Note 5)*	**-**	(3,306)
Cash distributions	**(114,958)**	(124,981)
	336,205	(49,613)
Investing Activities		
Corporate Acquisition *(Note 2)*	**(527,432)**	-
Disposition *(Note 2)*	**134,400**	-
Capital expenditures	**(173,373)**	(134,652)
Change in non-cash working capital *(Note 10)*	**1,506**	2,371
	(564,899)	(132,281)
Change in cash and short-term investments	**(8,265)**	8,265
Cash and short-term investments, beginning of year	**8,265**	-
Cash and short-term investments, end of year	**-**	8,265

See accompanying notes to the consolidated financial statements

Progress Energy Trust ("Progress" or the "Trust") is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties through investments in securities of subsidiaries and royalty interests in petroleum and natural gas properties. Progress Energy Ltd. carries on the business of the Trust and directly owns the petroleum and natural gas properties and assets related thereto. The Trust owns, directly and indirectly, 100 percent of the common shares (excluding the exchangeable shares – see note 7) of Progress Energy Ltd. The activities of Progress Energy Ltd. are financed through interest bearing notes from the Trust and third party debt. The convertible debentures are direct obligations of the Trust. Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust, which is primarily comprised of interest earned on debt notes issued to Progress Energy Ltd., as well as, amounts attributed to a net profits interest ("NPI") agreement entered into with Progress Energy Ltd. The aggregate amounts received by the Trust each period are based on the consolidated cash flow from operations before changes in non-cash working capital each period, as adjusted on a discretionary basis, for cash withheld to fund capital expenditures.

Pursuant to the terms of the NPI agreement, the Trust is entitled to a payment from Progress Energy Ltd. each month equal to the amount by which 99% of the gross proceeds from the sale of production exceed 99% of certain deductible expenditures (as defined). Under the terms of the NPI agreement, deductible expenditures may include amounts, determined on a discretionary basis, to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of Progress Energy Ltd.

Relationship with ProEx

A technical services agreement ("Technical Services Agreement") is currently in place between the Trust and ProEx Energy Ltd. ("ProEx") whereby the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expense reimbursed by ProEx for the year ended December 31, 2007 was $6.2 million (2006 - $4.5 million).

ProEx has granted stock options and shares to employees and executives of Progress as service providers and has also participated in a new long term incentive plan by granting ProEx common shares to employees of Progress, excluding the executives. To facilitate this plan, during 2007, Progress purchased 173,789 ProEx common shares and has been reimbursed by ProEx for the cost incurred. The ProEx common shares will be held until the vesting date, two years from date of grant. Any forfeited shares will revert back to ProEx.

The Trust and ProEx have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements and in addition, the Trust has entered into a Protocol Arrangement with ProEx that specifies how each company will manage the joint lands in specifically identified areas of interest. The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

On April 2, 2007, Progress acquired all of the issued and outstanding shares of a private company for $527.4 million net of certain assets retained by the vendor. In conjunction with the acquisition, on April 2, 2007, Progress disposed of certain assets of the private company to ProEx for $134.4 million. When considering the bid process for the acquisition, each of Progress and ProEx identified assets that they were interested in acquiring and values that they were willing to pay to acquire such assets. Progress made a single bid on behalf of ProEx and Progress and the ultimate purchase price was based on the prices that each of Progress and ProEx were willing to

pay for the assets that they had selected to acquire. The resale of assets from Progress to ProEx was based on these allocations. The technical services committee reviewed the details of the transaction prior to the purchase and sale agreement being signed. All lands are managed in accordance with the Protocol Arrangement.

On November 30, 2007, Progress and ProEx jointly acquired certain assets in the Foothills region of British Columbia. The total cost of the acquisition of $17.9 million was split in accordance with working interests currently held in the surrounding area. As a result, Progress acquired a 20 percent interest in the assets ($3.6 million) and ProEx an 80 percent interest ($14.3 million).

As at December 31, 2007, accounts payable included $0.6 million (2006 - $4.6 million) payable to ProEx which includes standard joint venture amounts including revenue. These amounts were paid subsequent to year end.

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

The Trust is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta and Saskatchewan. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiary.

Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Trust only reflects its proportionate interest in such activities.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the asset retirement obligations and related accretion are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Cash and Short-Term Investments

Cash and short-term investments consist of cash in the bank, less outstanding cheques, and short-term deposits with a maturity of less than three months.

Petroleum and Natural Gas Properties

The Trust uses the full cost method of accounting for petroleum and natural gas properties under which all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

In accordance with the full cost accounting guideline, the Trust evaluates its oil and gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the oil and gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of

proved plus probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion and Depreciation

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit-of-production method based on estimated proven reserves of petroleum and natural gas on a Trust interest basis (working interest plus royalty interest) before the deduction of crown and other royalties as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on a relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

Other assets, which are comprised of office equipment and furniture and fixtures, are recorded at cost and are depreciated over their useful life on a declining balance basis at 20 percent.

Asset Retirement Obligations

The Trust records a liability for the fair value of future asset retirement obligations in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset within property, plant and equipment, which is depleted on a unit-of-production basis over the life of the reserves. Estimates used are evaluated on a periodic basis and any adjustments are applied prospectively. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability. No gains or losses on retirement activities were realized due to settlements approximating the estimates.

Goodwill

Goodwill is recognized on corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets of the acquired company. Goodwill is tested for impairment on an annual basis in the fourth quarter. If indications of impairment are present, a loss would be charged to earnings for the amount that the carrying value of goodwill exceeds its fair value.

Financial Instruments

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Trust may enter into crude oil and natural gas swap contracts, options or collars to hedge its exposure to petroleum and natural gas commodity prices and may enter into foreign exchange forward contracts to hedge anticipated US dollar denominated petroleum and natural gas sales. The derivative financial instruments are initiated within the guidelines of the Trust's risk management policy and the Trust does not enter into derivative financial instruments for trading or speculative purposes.

On January 1, 2007 Progress adopted the new accounting standards regarding the recognition, measurement, disclosure and presentation of financial instruments. In conjunction with the adoption of these new standards, the Trust elected not to use hedge accounting for its natural gas derivative contracts under its risk management program. The fair value of the commodity contracts is recognized at each reporting period with the change in the fair value being classified as an unrealized gain or loss on the statement of earnings. In accordance with the transitional provisions of the standards, the accounting for hedging relationships for prior periods is not retroactively adjusted, therefore, there has been no restatement of the prior periods. On adoption, the Trust recognized a current asset of $15.6 million for the fair value of its natural gas derivative contracts and an increase to the future income tax liability and accumulated other comprehensive income of $5.1 million and $10.5 million, respectively. The $10.5 million in accumulated other comprehensive income was amortized through other comprehensive income and unrealized gain or loss on financial instruments on the statement of earnings over the term of the contracts. The commodity contracts expired in 2007 which resulted in the change in the fair value from January 1, 2007 of $15.6 million being offset by the amortization of other comprehensive income. Contracts

entered into by Progress subsequent to December 31, 2007 are disclosed in note 11. Certain comparative amounts have been reclassified to conform to the presentation adopted in 2007.

For the year ended December 31, 2007 the Company has early adopted the disclosures required under section 3862 Financial Instruments – Disclosures which applies to both recognized and unrecognized financial instruments. These disclosures, which include the nature and extent of risks arising from financial instruments, are included in note 11.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

Income Taxes

The Trust follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse. The benefit of any uncertain tax benefits, if any, are only recognized if it is probable that they would be realized.

The Trust is a taxable entity under the Income Tax Act (Canada) and, for periods prior to January 1, 2011, is taxable only on income that is not distributed or distributable to the unitholders. On June 12, 2007 the federal government's bill regarding the taxation of distributions from trusts beginning January 1, 2011 was enacted. Under this new law, distributions after January 1, 2011 will not be deductible by the Trust for tax purposes. As a result, a $6.6 million future income tax asset was recorded in June 2007 to recognize the future tax value for the amount the Trust's tax pools exceeded the carrying value of its assets. This resulted in a $6.6 million recovery which is included in the future income tax provision in the statement of earnings.

Unit Based Compensation

The Trust has established a Performance Unit Incentive Plan (the "Plan") for employees and directors of the Trust or its subsidiary. The Plan was modified in 2007 to include a new long term incentive component ("LTI component") for non-executive employees. The Trust uses the fair value method for valuing unit based compensation and unit option grants. Under this method, compensation cost attributed to performance units granted is measured at the fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the settlement of the Plan, the previously recognized value in contributed surplus will be recorded as an increase to unitholders' capital.

The Trust has not incorporated an estimated forfeiture rate for performance units that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

Per Unit Information

Per unit information is calculated on the basis of the weighted average number of trust units outstanding during the fiscal year. Diluted per unit information includes the impact of the issuable exchangeable shares, as well as, the potential dilution that could occur if securities or other contracts to issue units were exercised or converted to units. Diluted per unit information is calculated using the treasury stock method that assumes any proceeds received by the Trust upon the exercise of in-the-money unit options plus the unamortized unit compensation cost would be used to buy back trust units at the average market price for the period.

Exchangeable Securities – Non-Controlling Interest

The Trust accounts for outstanding exchangeable shares as non-controlling interest given exchangeable shareholders can dispose of their shares without having to exchange them for trust units. The exchangeable shares of the Trust's subsidiary trade on the Toronto Stock Exchange. As a result, the exchangeable shares have been classified as non-controlling interest on the consolidated balance sheet outside of unitholders' equity. Net earnings attributable to the exchangeable shares is charged to the consolidated statement of earnings as non-controlling interest expense with a corresponding increase to non-controlling interest on the consolidated balance sheet.

Each redemption of exchangeable shares held by previous Progress Energy Ltd. shareholders is accounted for as a step-purchase resulting in an increase to property, plant and equipment, an increase to unitholders' capital and an decrease in the Trust's future income tax asset. The non-controlling interest activity for the years ended December 31, 2007 and 2006 is disclosed in note 7.

2. CORPORATE ACQUISITION

On April 2, 2007 Progress acquired all of the issued and outstanding shares of a private company for $527.4 million, net of certain assets retained by the vendor. In conjunction with the acquisition, on April 2, 2007, Progress disposed of certain assets of the private company to ProEx for $134.4 million. The resulting net cash consideration of $393.0 million was financed by the issuance of 21,000,000 trust units at a price of $12.00 per trust unit for proceeds of $252.0 million ($238.7 million net of issue costs) and through increased bank debt. Included in the acquisition was approximately $720.9 million of tax pools which are available to Progress to shelter future taxable income. As a result a $137.2 million future income tax asset was recognized on the acquisition. Using the purchase method of accounting, the net assets acquired and consideration paid were as follows:

Net assets acquired	
Working capital	3,965
Bank debt	(9,123)
Property, plant and equipment	266,625
Future income taxes	137,203
Asset retirement obligations	(5,638)
Total net assets acquired	393,032

Consideration	
Cash	523,166
Proceeds of asset disposition	(134,400)
Acquisition costs	4,266
Total purchase price	393,032

3. PROPERTY, PLANT AND EQUIPMENT

	2007	2006
Property, plant and equipment	1,447,181	1,001,785
Conversion of exchangeable shares	47,461	46,014
Accumulated depletion and depreciation	(439,588)	(303,368)
Property, plant and equipment, net	1,055,054	744,431

On May 31, 2007 Progress acquired certain petroleum and natural gas assets in the Deep Basin region of northwest Alberta for $41.3 million, net of final closing adjustments.

On November 30, 2007, Progress and ProEx jointly acquired certain assets in the Foothills region of British Columbia. Progress took a 20 percent portion of the assets acquired amounting to $3.6 million.

In June 2006, the Trust disposed of its assets in the Unity, Saskatchewan area to a private company for 2,860,000 common shares valued at $1.20 per share for a total consideration of $3.4 million.

As described in note 1, the redemption of exchangeable shares held by previous Progress Energy Ltd. shareholders are accounted for as a step-purchase. Consequently, a charge of $1.4 million was made to property, plant and equipment for the year ended December 31, 2007 (2006 - $13.5 million).

The calculation of 2007 depletion and depreciation included an estimated $78.9 million (2006 - $34.5 million) for future development costs associated with proved undeveloped reserves and excluded $26.7 million (2006 - $24.0 million) for the estimated future net realizable value of production equipment and facilities and $96.2 million (2006 - $58.2 million) for the estimated value of unproven properties. Depletion and depreciation expense for the year ended December 31, 2007 was $136.2 million (2006 - $93.0 million).

Included in the Trust's property, plant and equipment balance is $20.9 million (2006 - $14.8 million), net of accumulated depletion, related to asset retirement obligations ($31.9 million before accumulated depletion (2006 - $22.9 million)) (Refer to note 6).

The Trust capitalized approximately $3.5 million of geological and geophysical expenses and compensation costs associated with the exploration and development of capital assets during the year ended December 31, 2007 (2006 - $2.4 million).

The Trust performed a ceiling test calculation at December 31, 2007 resulting in the undiscounted cash flows from proved reserves and the lower of cost and market of unproved properties exceeding the carrying value of oil and gas assets. The following table summarizes the future benchmark prices the Trust used in the ceiling test:

	Crude Oil		Natural Gas
	West Texas Intermediate (Cdn$/bbl) (1)	Edmonton Par Price (Cdn$/bbl)	AECO Gas price (Cdn$/mmbtu)
2008	92.00	91.10	6.75
2009	88.00	87.10	7.55
2010	84.00	83.10	7.60
2011	82.00	81.10	7.60
2012	82.00	81.10	7.60
2013-2017 (2)	82.34	81.44	7.96
Thereafter (3)	2.0%	2.0%	2.0%

(1) Future prices incorporated a $1.00 US/Cdn exchange rate.

(2) Prices shown are the average over the period.

(3) Percentage change of 2.0% represents the change in future prices each year after 2017 to the end of the reserve life.

4. BANK DEBT

	2007	2006
Direct advances	**1,590**	-
Banker's acceptances	**295,000**	75,000
Total bank debt	**296,590**	75,000

The Trust's credit facilities totaling $375 million are with a syndicate of banks consisting of a $340 million extendible revolving term credit facility and a $35 million working capital credit facility. The facilities are available on a revolving basis for a period of at least 364 days until May 27, 2008, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. Various borrowing options are available under the facilities including prime rate based advances and banker's acceptance loans. Average cost of borrowing under these facilities for the year ended December 31, 2007 was 5.5 percent (2006 – 5.1 percent). The credit facilities are secured by a $1 billion fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress Energy Ltd. in respect of the Trust's obligations. The $375 million borrowing base is subject to semi-annual review by the banks.

5. CONVERTIBLE DEBENTURES

On August 22, 2006 the Trust issued $75.0 million principal amount of 6.25 percent convertible unsecured subordinated debentures (the "6.25 percent debentures") for net proceeds of $71.7 million. The 6.25 percent debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $19.50 per trust unit. The 6.25 percent debentures mature on September 30, 2011, at which time they are due and payable. The Trust may elect to satisfy the interest and principal obligations by the issuance of trust units. The net proceeds were used to reduce outstanding bank indebtedness.

The 6.75 percent convertible unsecured subordinated debentures (the "6.75 percent debentures") pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $15.00 per trust unit. The 6.75 percent debentures mature on June 30, 2010 at which time they are due and payable. The Trust may elect to satisfy the interest and principal obligations by the issuance of trust units. The net proceeds were used to reduce outstanding bank indebtedness.

The 6.25 percent debentures and the 6.75 percent debentures (the "Debentures") have been classified as debt, net of issue costs and net of the fair value of the conversion feature at the date of issue which has been classified as part of unitholders' equity. The issue costs will be amortized over the term of the Debentures and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed within interest and financing expense on the consolidated statements of earnings. If the Debentures are converted to units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the conversion price paid. The following table sets forth a reconciliation of the Debenture activity:

		2007			2006	
	6.75%	6.25%	**Total**	6.75%	6.25%	Total
Principal, beginning of year(1)	55,727	75,000	**130,727**	86,182	75,000	161,182
Converted to trust units	-	-	**-**	(30,455)	-	(30,455)
Principal, end of year	55,727	75,000	**130,727**	55,727	75,000	130,727
Debt portion, beginning of year(1)	52,300	67,305	**119,605**	79,381	66,748	146,129
Accretion	508	945	**1,453**	535	337	872
Amortization of issue costs	466	650	**1,116**	497	220	717
Conversions to trust units(2)	-	-	**-**	(28,113)	-	(28,113)
Debt portion, end of year	53,274	68,900	**122,174**	52,300	67,305	119,605
Equity portion, beginning of year(1)	2,756	4,946	**7,702**	4,261	4,946	9,207
Conversions to trust units	-	-	**-**	(1,505)	-	(1,505)
Equity portion, end of year	2,756	4,946	**7,702**	2,756	4,946	7,702

(1) The 6.75 percent debentures were issued February 2, 2005 and the 6.25 percent debentures were issued August 22, 2006.
(2) Net of unamortized issue costs.

Total interest charged to earnings for the year ended December 31, 2007 was $11.0 million (2006 - $7.4 million) which includes $1.5 million of debenture accretion (2006 - $0.9 million) and $1.1 million of amortized issue costs (2006 - $0.7 million).

6. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligations is approximately $75.9 million which will be incurred over the next 40 years with the majority of costs incurred between 2009 and 2020. A credit adjusted risk-free rate of eight percent was used to calculate the fair value of the asset retirement obligations.

The following reconciles the Trust's asset retirement obligations:

	2007	2006
Balance, beginning of year	24,148	20,906
Liabilities incurred	3,523	4,580
Liabilities settled	(713)	(2,714)
Acquisition *(Note 2)*	5,638	-
Dispositions	-	(374)
Accretion expense	2,416	1,750
Balance, end of year	35,012	24,148

7. NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares issued to Progress Energy Ltd. shareholders and the fair value of exchangeable shares issued to Cequel Energy Inc. shareholders as part of a Plan of Arrangement that became effective on July 2, 2004, plus net earnings attributable to the exchangeable shares, less exchangeable shares (and related cumulative earnings) redeemed. The non-controlling interest charge on the consolidated statement of earnings represents the share of net earnings attributable to the exchangeable shares based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end. The activity for non-controlling interest for the year ended December 31, 2007 and 2006 is as follows:

	2007		2006	
Exchangeable shares	**Number**	**Amount**	Number	Amount
Balance, beginning of year	9,642,540	122,592	11,388,751	127,205
Exchanged for trust units	(469,457)	(6,132)	(1,746,211)	(20,130)
Non-controlling interest expense		9,924		15,517
Balance, end of year	9,173,083	126,384	9,642,540	122,592

The exchangeable shares can be converted, at the option of the holder, into trust units at any time and are listed on the Toronto Stock Exchange under the symbol PGE. If the number of exchangeable shares outstanding is less than 1,600,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchange ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for cash distributions.

Retraction of Exchangeable Shares

Shareholders of exchangeable shares may redeem their shares at any time by delivering their share certificates to the Trustee, together with a properly completed retraction request. The retraction price will be satisfied with trust units equal to the amount determined by multiplying the exchange ratio on the last business day prior to the retraction date by the number of exchangeable shares redeemed.

Redemption of Exchangeable Shares

On July 2, 2009 the exchangeable shares will be redeemed by the Trust unless the Board of Directors of Progress Energy Ltd. elect to extend the redemption period. The exchangeable shares will be redeemed by either issuing units or payment in cash for an amount equivalent to the value of the exchangeable shares at the current exchange ratio.

8. UNITHOLDERS' CAPITAL

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges.

	2007		2006	
	Number	**Amount**	Number	Amount
Trust Units				
Balance, beginning of year	**75,457,291**	**739,998**	71,302,265	681,263
Issued for cash *(Note 2)*	**21,000,000**	**252,000**	-	-
Exchangeable shares converted	**640,150**	**7,150**	2,124,705	29,117
Unit based compensation	**381,367**	**5,102**	-	-
Issued on conversion of Debentures	-	-	2,030,321	29,618
Unit issue costs *(Note 2)*		**(13,304)**		-
Balance, end of year	**97,478,808**	**990,946**	75,457,291	739,998

On June 28, 2007 381,367 units were issued to settle the performance units vesting on July 2, 2007, resulting in $5.1 million being transferred from contributed surplus to unitholders' capital.

Management of Capital Structure

Progress' objectives when managing capital are: (i) to maintain a flexible capital structure which optimizes the cost of capital at acceptable risk; and (ii) to manage capital in a manner which balances the interests of equity and debt holders.

In the management of capital, Progress includes bank debt, convertible unsecured debentures and working capital ("total debt"). Progress manages the capital structure and makes adjustments in light of changes in economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure Progress may adjust the amount of distributions paid to unitholders, issue new units, issue new debt, issue new debt to replace existing debt with different characteristics, adjust exploration and development capital expenditures, and acquire or dispose of assets.

Consistent with the practice of other trusts in the oil and gas sector, Progress monitors capital based on the non-GAAP ratio, "total debt-to-cash flow from operations (before changes in non-cash working capital)". As at December 31, 2007 Progress' ratio of total debt-to-cash flow from operations (before changes in non-cash working capital) was 2.1 times (2006 – 1.1 times). Total debt-to-cash-flow from operations (before changes in non-cash working capital is calculated by dividing total debt at the end of the period (comprising of the working capital deficit, outstanding bank debt and the debt portion of Progress' convertible unsecured debentures) by the 12 month trailing cash flow from operations (before changes in non-cash working capital). In 2006, Progress targeted a ratio of 1.0 times total debt-to-cash flow from operations (before changes in non-cash working capital) to position the Trust to take advantage of asset acquisitions. In the second quarter of 2007, Progress completed two significant acquisitions which resulted in a higher ratio of total debt-to-cash flow from operations (before changes in non-cash working capital). Based on current natural gas prices Progress is targeting a total debt-to-cash flow from operations (before changes in non-cash working capital) ratio of 1.5 to 2.0 times, slightly below the ratio as at December 31, 2007.

Redemption Right

Unitholders may redeem their trust units for cash at any time, up to a maximum of $250,000 in any calendar month, by delivering their unit certificates to the Trustee, together with a properly completed notice requesting redemption. The redemption amount per trust unit will be the lesser of 90 percent of the simple average closing price of the trust units on the principal market on which they are traded for the 10 day trading period after the trust

units have been validly tendered for the redemption and the closing market price of the trust units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or if there was no trade of the trust units on that date, the average of the last bid and ask prices of the trust units on that date.

Net Earnings Per Unit

The following table summarizes the weighted average trust units used in calculating net earnings per unit:

	2007	2006
Weighted average trust units - basic	**91,823,317**	74,536,584
Trust units issuable on conversion of exchangeable shares(1)	**13,542,906**	13,267,333
Performance units	**676,151**	477,461
Weighted average trust units - diluted	**106,042,374**	88,281,378

(1) Calculated based on the weighted average exchangeable shares outstanding during the year at the year end exchange ratio.

An adjustment to the numerator of $9.9 million for the year ended December 31, 2007 (2006 - $15.5 million) is required in the diluted earnings per unit calculation to provide for earnings attributable to non-controlling interest. Units potentially issuable on the conversion of the Debentures are anti-dilutive and are not included in the calculation of diluted weighted average units for the years ended December 31, 2007 and 2006.

Performance Unit Incentive Plan

The Trust has established a Performance Unit Incentive Plan (the "Plan") for employees and directors of the Trust or its subsidiary that includes both performance units and units under a long term incentive component. The number of units reserved for issuance under the Plan shall not exceed 5 percent of the aggregate number of issued and outstanding units of the Trust and including the number of units which may be issued on the exchange of the outstanding exchangeable shares, which may be converted into trust units.

Performance Units
Under the Plan, performance units shall be granted by the Board of Directors of Progress Energy Ltd. from time to time at its sole discretion. The performance units will vest on the third anniversary of the date of grant and actual payment will be determined based on the performance of the Trust relative to its peers. Performance factors range from 0.5 to 1.5 times the initial performance units granted except for performance units granted to the Trust's executives effective in 2007 which can range from 0 to 3 times. Over the three year term the performance units will attract distributions. The Trust expects to pay out the distribution portion in cash while the units earned will be issued from treasury.

Long Term Incentive Component
During 2007, the Plan was modified to include a new long term incentive component ("LTI component") for non-executive employees. Awards granted under the LTI component of the Plan will vest over three years with 40 percent vesting on the second anniversary of the date of grant and 60 percent vesting on the third anniversary of the date of grant. An additional 15 percent grant will be paid if the holder holds the units received on the second anniversary date for one additional year. As at December 31, 2007, 189,485 units are outstanding under the LTI component at an average value of $14.00 per unit, resulting in a total compensation cost of $2.7 million of which $2.3 million will be recognized through unit based compensation expense and $0.4 million will be capitalized over the vesting period.

On June 28, 2007 381,367 units were issued to settle the performance units that vested on July 2, 2007, resulting in $5.1 million being transferred from contributed surplus to unitholders' capital.

As at December 31, 2007 there are 481,800 performance units outstanding that were granted in 2005. During 2007 the estimated performance factor for this grant was increased from 1.0 to 1.5 based on the Trust's operating performance. The fair value of the performance units using a performance factor of 1.5 is approximately $10.9 million of which $9.6 million will be amortized through unit based compensation expense and $1.3 million will be

capitalized over the vesting period with a corresponding increase to contributed surplus. Actual performance factors will not be determined until the end of the performance period.

As at December 31, 2007 there are 401,850 performance units outstanding that were granted in 2006. During 2007 the estimated performance factor for this grant was increased from 1.0 to 1.5 based on the Trust's operating performance. The fair value of the performance units using a performance factor of 1.5 is approximately $9.1 million of which $8.0 million will be amortized through unit based compensation expense and $1.1 million will be capitalized over the vesting period with a corresponding increase to contributed surplus. Actual performance factors will not be determined until the end of the performance period.

As at December 31, 2007 there are 504,550 performance units outstanding that were granted in 2007. The fair value of the performance units using a performance factor of 1.0 is approximately $6.5 million of which $5.8 million will be amortized through unit based compensation expense and $0.7 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

For the year ended December 31, 2007 $9.0 million (2006 – $4.9 million) was charged to unit based compensation expense and $1.9 million (2006 – $0.8 million) was capitalized relating to the total performance units and units under the LTI component outstanding.

	2007	2006
Performance Units		
Balance, beginning of year	**1,300,717**	899,567
Granted	**521,450**	424,950
Settled	**(381,367)**	-
Forfeited	**(52,600)**	(23,800)
Balance, end of year	**1,388,200**	1,300,717
Vesting Date		
2007	**-**	380,567
2008[1]	**481,800**	512,300
2009[1]	**401,850**	407,850
2010	**504,550**	-
Total	**1,388,200**	1,300,717

(1) Using the current anticipated performance factor of 1.5 times, 722,700 units and 602,775 units, respectively, will be issued on the vesting of the 2008 and 2009 performance units.

	2007	2006
Units under LTI Component		
Balance, beginning of year	-	-
Granted	198,629	-
Forfeited	(9,144)	-
Balance, end of year	189,485	-
Vesting Date		
2009	75,794	-
2010	113,691	-
Total[1]	189,485	-

(1) If the units vesting in 2009 are held by the LTI holder until 2010, one year after date of vesting, an additional 28,423 units will be issued by the Trust.

Contributed Surplus

The following table reconciles the Trust's contributed surplus:

	2007	2006
Balance, beginning of year	9,210	3,530
Unit based compensation expense	9,037	4,874
Unit based compensation capitalized	1,323	806
Settlements	(5,102)	-
Balance, end of year	14,468	9,210

Accumulated other comprehensive income

As described in note 1, the adoption of the new accounting policies regarding financial instruments resulted in an amount being recognized in accumulated other comprehensive income for the fair value of the Trust's natural gas derivative contracts at January 1, 2007. The amount recognized in accumulated other comprehensive income was \$10.5 million, representing the value of the asset of \$15.6 million net of future income taxes of \$5.1 million. The amount was charged to the statement of earnings over the term of the contracts with a corresponding decrease to other comprehensive income.

	2007	2006
Balance, beginning of year	-	-
Change in accounting policy, net of tax of \$5,072 *(Note 1)*	10,543	-
Amortization of fair value of financial instruments, net of tax	(10,543)	-
Balance, end of period	-	-

9. FUTURE INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and, for periods prior to January 1, 2011, is taxable only on income that is not distributed or distributable to the unitholders. On June 12, 2007 the federal government's bill regarding the taxation of distributions from trusts beginning January 1, 2011 was enacted. Under this new law, distributions after January 1, 2011 will not be deductible by the Trust for tax purposes. As a result, a \$6.6 million future income tax asset was recorded in June 2007 to recognize the future tax value for the amount the Trust's tax pools exceeded the carrying value of its assets. This resulted in a \$6.6 million recovery which is included in the future income tax provision in the statement of earnings. Cash distributions for the year ended December 31, 2007 totaled \$114.1 million (2006 - \$125.6 million), reducing the Trust's expected future income tax expense for the year.

Included in the 2007 provision is a loss of $2.3 million relating to a reduction in future federal income tax rates, which reduces the value of Progress' future income tax asset. Included in the 2006 provision is a recovery of $9.2 million relating to a reduction in future federal and provincial tax rates enacted during the year, which reduced the value of Progress future income tax liability at that time, and the impact of certain tax balance adjustments.

The provision for future income taxes in the consolidated statements of earnings reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

	2007	2006
Earnings before taxes	**65,392**	92,622
Statutory income tax rate	**32.5%**	34.8%
Expected income taxes	**21,252**	32,232
Add (deduct)		
Net income of the Trust[1]	**(16,037)**	(39,660)
Taxable income designated to Unitholders[1]	**(18,506)**	-
Change in tax law[1]	**(6,589)**	-
Non-deductible crown charges	**-**	7,940
Resource allowance	**-**	(7,470)
Reduction in income tax rates and certain tax balance	**2,344**	(9,212)
Income tax audit adjustments	**-**	129
Attributed Canadian Royalty Income	**-**	(216)
Other	**2,675**	1,584
	(14,861)	(14,673)

(1) Prior to June 2007, no future income taxes were recognized for the Trust (only future income taxes relating to the Trust's subsidiary were recognized). Consequently all income of the Trust had no future income tax implications and therefore was a reconciling item to the expense on the statement of earnings. As a result of the law enacted in June 2007, future income taxes are now recognized at the Trust level and therefore, after June 2007, only the taxable portion of distributions to unitholders is included in the reconciliation above.

The future income taxes liability at December 31 is comprised of the tax effect of temporary differences as follows:

	2007	2006
Property, plant and equipment	**16,190**	(124,460)
Asset retirement obligations	**8,897**	7,268
Non capital losses	**6,047**	-
Commodity sales contracts	**111**	260
Share issue costs	**641**	138
Attributed Canadian Royalty Income	**4,830**	2,427
	36,716	(114,367)

As at December 31, 2007, the Trust's corporate subsidiary, Progress Energy Ltd., has federal tax pools of $1.1 billion (2006 - $268.0 million) available for deduction against future taxable income. The Trust currently has tax pools available of $93.7 million.

The following are the combined tax pools available for the Trust and its corporate subsidiary:

	2007
Canadian exploration expense	515,000
Canadian development expense	222,000
Canadian oil and gas property expense	159,000
Undepreciated capital cost	224,000
Non-capital losses	17,000
Share issue costs	15,000
Attributed Canadian Royalty Income	61,000

10. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	2007	2006
Accounts receivable	14,696	10,315
Prepaid expenses and deposits	(1,349)	778
Accounts payables	(5,746)	(9,084)
Current income taxes payable	44	192
Change in non-cash working capital	7,645	2,201
Relating to:		
Investing activities	1,506	2,371
Operating activities	6,139	(170)

Interest and taxes paid

	2007	2006
Interest paid	21,564	8,641
Income and other taxes paid	82	182

11. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The Trust's financial instruments recognized on the balance sheet consist of accounts receivable, accounts payable and accrued liabilities, bank debt and convertible debentures. The fair value of these instruments, excluding the convertible debentures, approximate their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank debt. The fair value of the convertible debentures outstanding as at December 31, 2007, based on quoted market prices, was approximately \$123.0 million (2006 - \$130.2 million). From time to time Progress enters into derivative natural gas contracts ("financial instruments") however, at December 31, 2007 there were no natural gas contracts outstanding.

Credit risk

The Trust's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. The Trust routinely assesses the financial strength of its customers.

The Trust may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. The Trust mitigates this risk by entering into transactions with highly rated major financial institutions.

At December 31, 2007, financial assets on the balance sheet are comprised of accounts receivables and a $4.1 million equity investment in a private company within prepaid expenses and deposits. There were no natural gas derivative contracts outstanding at December 31, 2007. The investment in the private company is classified as an available for sale financial asset, however as there is no quoted market price in an active market, the investment is measured at cost.

The maximum credit exposure at December 31, 2007 is the carrying amount of accounts receivable of $47.5 million. As is common in the petroleum and natural gas industry in western Canada, receivables relating to the sale of petroleum and natural gas are received on or about the 25th day of the following month. The Trust markets its production to customers with investment grade credit ratings, if available in the area of production, or seeks parental guarantees and letters of credit. Of the $47.5 million accounts receivable outstanding, $36.2 related to the sale of petroleum and natural gas and was received January 25, 2008. The accounts receivable balance includes $7.6 million from joint venture partners relating to the recovery of their interest in operating costs and capital spent. The largest amount owing from one partner was $1.4 million. As the operator of properties, Progress has the ability to not allocate production to joint venture partners who are in default of amounts owing. At December 31, 2007 there was no material allowance for the impairment of accounts receivable.

Currency risk

The Trust does not sell or transact in any foreign currency, however, the United States dollar influences the price of petroleum and natural gas sold in Canada. Price fluctuations, as a result, can affect the fair value and future cash flows of derivative natural gas contracts, however, given it is an indirect influence, the impact of changing exchange rates cannot be quantified. There were no derivative natural gas contracts outstanding at December 31, 2007. The Trust's other financial assets and liabilities are not directly affected by a change in currency rates.

Interest rate risk

The Trust is exposed to interest rate risk on its outstanding bank debt and Debentures. The bank debt has a floating interest rate and consequently changes to interest rates would impact the Trust's future cash flows. The Company had no interest rate swaps or hedges at December 31, 2007. Changes in market interest rates will result in fluctuations to the fair value of the Debenture's given their fixed interest rates.

Liquidity risk

Liquidity risk relates to the risk the Trust will encounter difficulty in meeting obligations associated with its financial liabilities. The financial liabilities on its balance sheet consist of accounts payable, bank debt and the Debentures. The credit facilities are available on a revolving basis for a period of at least 364 days until May 27, 2008, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. The Debentures mature in June 2010 and September 2011. The Trust anticipates it will continue to have adequate liquidity to fund its financial liabilities through its future cash flows (see also "Management of Capital Structure" in note 8). The Trust had no defaults or breaches on its bank debt or any of its financial liabilities.

Market risk

Market risk is comprised of currency risk, interest rate risk and other price risks which consist primarily of fluctuations in petroleum and natural gas prices. The valuation of the financial assets and liabilities on the balance sheet at December 31, 2007 would not be directly impacted by changes in currency rates. Currency rates influence petroleum and natural gas prices, however this influence on commodity prices and the resulting impact on financial assets and liabilities cannot be accurately quantified. In regards to interest rate risk, an increase or decrease of one percent to the effective interest rate for the Trust would have impacted net earnings by $1.5 million for the year. In regards to commodity prices, a one dollar change in the price per barrel of crude oil would have impacted net earnings by $0.5 million and a $0.25 change to the price per thousand cubic feet of natural gas would have impacted net earnings by $7.2 million.

Commodity Price Contracts

There were no derivative natural gas financial instruments outstanding as at December 31, 2007. Subsequent to December 31, 2007 the Trust entered into several derivative financial instruments for the purpose of protecting its cash flow from operations before changes in non-cash working capital from the volatility of natural gas prices. For the year ended December 31, 2007, the Trust's natural gas price risk management program had a net gain of $16.1 million (2006 - $29.9 million).

As described in note 1, the Trust recognizes the fair value of its commodity price contracts on the balance sheet each reporting period with the change in fair value being recognized as an unrealized gain or loss on the statement of earnings. On January 1, 2007 the fair value of the commodity price contracts was an asset of $15.6 million and resulted in an increase to accumulated other comprehensive income and the future income tax liability of $10.5 million and $5.1 million, respectively. The $10.5 million recognized in accumulated other comprehensive income was amortized over the term of the contracts through other comprehensive income with a corresponding unrealized gain on financial instruments on the statement of earnings. As a result, for the year ended December 31, 2007 $10.5 million, net of tax, was charged to other comprehensive income with a corresponding unrealized gain on financial instruments of $15.6 million and a charge to future income tax expense of $5.1 million. The unrealized gain of $15.6 million was offset by the change in fair value from January 1, 2007 of $15.6 million resulting in an unrealized gain of nil for 2007.

Contracts entered into subsequent to December 31, 2007 are as follows:

Natural Gas Contracts(1)	Volume	Pricing Point	Strike Price $/gj(1)	Cost/ Premium	Term
Fixed Price Swap	10,000 gj/d	AECO	6.70	-	April 1 to October 31, 2008
Fixed Price Swap	10,000 gj/d	AECO	6.78	-	April 1 to October 31, 2008
Swap - call spread	10,000 gj/d	AECO	$7.50 - $8.50	$0.365/gj	April 1 to October 31, 2008
Swap - call spread	10,000 gj/d	AECO	$7.39 - $8.39	$0.370/gj	April 1 to October 31, 2008
Swap - call spread	10,000 gj/d	AECO	$7.095 - $8.095	$0.355/gj	April 1 to October 31, 2008
Swap - call spread	10,000 gj/d	AECO	$7.13 - $8.13	$0.355/gj	April 1 to October 31, 2008
Swap - call spread	10,000 gj/d	AECO	$7.23 - $8.23	$0.355/gj	April 1 to October 31, 2008
Swap - call spread	5,000 gj/d	AECO	$7.21 - $8.21	$0.360/gj	April 1 to October 31, 2008
Swap - call spread	5,000 gj/d	AECO	$7.24 - $8.24	$0.360/gj	April 1 to October 31, 2008

(1) *Call spread strike prices indicate minimum floor and maximum ceiling*

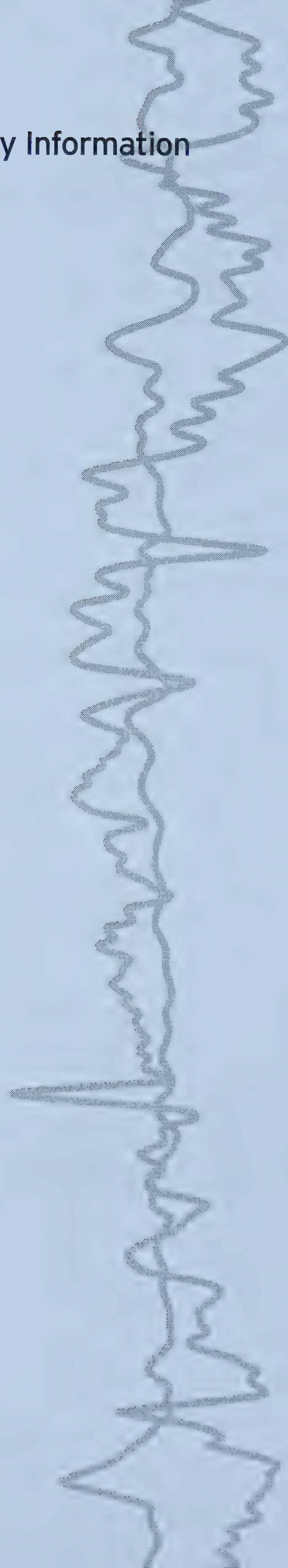
12. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation contracts, drilling rig agreements, compressor rentals and office space. The Trust's extendible term credit facility is available on a revolving basis until May 27, 2008. This initial term out date may be extended for a further 364 day period at the request of the Company, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term. Without assuming the renewal of the credit facilities payments required under these commitments for each of the next five years are: 2008 - $23.6 million; 2009 - $311.4 million; 2010 - $66.7 million; 2011 - $82.8 million; and 2012 - $1.3 million. Future commitments related to bank debt and the Debentures are disclosed in notes 4 and 5, respectively.

Progress Energy Trust

Selected Quarterly Information

2006 and 2007



2007 SELECTED QUARTERLY INFORMATION

FINANCIAL HIGHLIGHTS *($ thousands except per unit amounts)*	Three Months Ended 2007 March 31	June 30	Sept. 30	Dec. 31	Annual 2007
Income Statement					
Petroleum and natural gas revenue	85,477	108,503	88,480	99,592	**382,052**
Cash flow [1]	53,080	58,398	48,085	54,727	**214,290**
Per unit – diluted	0.60	0.53	0.43	0.49	**2.02**
Cash distributions declared	24,831	29,092	30,987	29,232	**114,142**
Per unit	0.30	0.30	0.30	0.30	**1.20**
Net earnings	16,425	31,947	11,909	9,922	**70,203**
Per unit – basic	0.22	0.33	0.12	0.10	**0.76**
Per unit – diluted	0.22	0.33	0.12	0.10	**0.76**
Payout Ratio					
Excluding exchangeable shares	47%	50%	64%	53%	**53%**
Including exchangeable shares	54%	56%	73%	61%	**61%**
Balance Sheet					
Exploration and development capital	43,384	14,677	31,726	47,210	**136,997**
Net property acquisitions (dispositions)	217	41,157	(8,293)	3,295	**36,375**
Total capital expenditures	43,601	55,834	23,433	50,505	**173,372**
Corporation Acquisition[3]	-	389,363	-	3,669	**393,032**
Total debt	252,000	410,696	417,678	444,223	**444,223**
Unitholders' equity	689,909	933,606	916,357	900,806	**900,806**
Trust Units *(thousands except where otherwise stated)*					
Units outstanding, end of period	75,799	97,262	97,344	97,479	**97,479**
Units issuable for exchangeable shares	12,665	12,859	13,093	13,302	**13,302**
Total units outstanding and issuable for exchangeable shares, end of period	88,464	110,121	110,437	110,781	**110,781**
Weighted average units - diluted[2]	89,039	109,965	110,936	111,413	**106,042**
Exchange ratio, end of period	1.34944	1.37885	1.41278	1.45015	**1.45015**
Trust Unit Trading Statistics *($)*					
High	13.29	15.79	13.44	12.25	**15.79**
Low	11.00	12.76	10.96	9.92	**9.92**
Closing	13.07	12.93	12.03	10.85	**10.85**
Unit volume traded (thousands)	23,116	23,310	25,679	20,726	**92,831**
Exchangeable Shares Trading Statistics *($)*					
High	17.50	20.50	18.15	17.00	**20.50**
Low	14.84	17.90	15.01	14.50	**14.50**
Closing	17.60	18.60	16.51	15.15	**15.15**
Share volume traded (thousands)	13	27	92	104	**236**

[1] See discussion in the Management Discussion and Analysis

[2] Includes exchangeable shares converted at the end of period exchange ratio.

3 Net of the disposition of assets to ProEx.

2007 SELECTED QUARTERLY INFORMATION

Operational Highlights	Three Months Ended 2007				Annual
	March 31	**June 30**	**Sept. 30**	**Dec. 31**	**2007**
Daily Production					
Natural gas (mcf/d)	94,351	127,255	120,804	123,740	**116,630**
Crude oil (bbls/d)	2,118	2,134	2,268	2,068	**2,147**
Natural gas liquids (bbls/d)	1,379	1,485	1,370	1,548	**1,446**
Total daily production (boe/d)	19,222	24,828	23,772	24,240	**23,031**
Average Realized Prices					
Natural gas ($/mcf)	7.87	7.52	5.77	6.49	**6.85**
Crude oil ($/bbl)	62.15	68.37	78.77	81.67	**72.86**
Natural gas liquids ($/bbl)	55.08	60.51	62.91	71.51	**62.77**
Highlights ($/boe)					
Weighted average sales price	49.41	48.03	40.46	44.66	**45.45**
Realized gain on financial instruments	4.04	0.08	2.89	1.14	**1.91**
Royalties	(11.67)	(10.51)	(8.80)	(9.54)	**(10.04)**
Operating expenses	(6.38)	(6.57)	(6.67)	(5.91)	**(6.38)**
Transportation expenses	(1.60)	(1.85)	(1.96)	(1.86)	**(1.83)**
Operating Netbacks	33.80	29.18	25.92	28.49	**29.11**
Other Income	-	0.09	0.01	-	**0.02**
General and administrative expense	(1.14)	(1.02)	(1.12)	(0.90)	**(1.04)**
Unit based compensation	(0.86)	(1.13)	(1.09)	(1.16)	**(1.08)**
Interest and financing expenses	(2.19)	(2.61)	(2.88)	(3.16)	**(2.74)**
Unrealized gain/(loss) on financial instruments	(4.76)	4.65	(0.27)	(0.75)	**-**
Depletion, depreciation and accretion	(14.91)	(16.94)	(17.08)	(16.70)	**(16.49)**
Net earnings before taxes	9.94	12.22	3.49	5.82	**7.78**
Capital taxes	(0.03)	(0.02)	(0.02)	(0.01)	**(0.02)**
Future income taxes recovery/(expense)	1.16	3.82	2.71	(0.76)	**1.77**
Non-controlling interest – exchangeable shares	(1.58)	(1.88)	(0.73)	(0.60)	**(1.18)**
Net Earnings	9.49	14.14	5.45	4.45	**8.35**
Drilling Results					
Gross	30	6	17	39	**92**
Net – natural gas	11.7	4.7	9.3	19.3	**45.0**
Net – crude oil	-	-	-	-	**-**
Success Rate (percent)	87	100	100	96	**95**

2006 SELECTED QUARTERLY INFORMATION

FINANCIAL HIGHLIGHTS *($ thousands except per unit amounts)*	Three Months Ended 2006 March 31	 June 30	 Sept. 30	 Dec. 31	Annual 2006
Income Statement					
Petroleum and natural gas revenue	91,568	71,439	72,328	75,183	**310,518**
Cash flow [1]	47,637	45,871	47,218	49,603	**190,329**
Per unit – diluted	0.55	0.52	0.54	0.56	**2.16**
Cash distributions declared	30,836	31,412	31,626	31,689	**125,563**
Per unit	0.42	0.42	0.42	0.42	**1.68**
Net earnings	21,383	28,425	20,252	21,538	**91,598**
Per unit – basic	0.29	0.38	0.27	0.29	**1.23**
Per unit – diluted	0.29	0.38	0.27	0.28	**1.21**
Payout Ratio					
Excluding exchangeable shares	65%	68%	67%	64%	**66%**
Including exchangeable shares	76%	80%	78%	75%	**78%**
Balance Sheet					
Exploration and development capital	35,686	31,839	30,887	35,474	**133,886**
Net property acquisitions (dispositions)	298	650	(12)	(170)	**766**
Total capital expenditures	35,984	32,489	30,875	35,304	**134,652**
Total debt	172,106	182,873	190,531	209,440	**209,440**
Unitholders' equity	687,953	694,236	696,844	688,539	**688,539**
Trust Units *(thousands except where otherwise stated)*					
Units outstanding, end of period	74,315	74,901	75,448	75,457	**75,457**
Units issuable for exchangeable shares	12,309	12,314	12,301	12,657	**12,657**
Total units outstanding and issuable for exchangeable shares, end of period	86,624	87,215	87,749	88,114	**88,114**
Weighted average units - diluted[2]	86,579	87,557	88,190	88,623	**88,281**
Exchange ratio, end of period	1.21322	1.24284	1.27469	1.31263	**1.31263**
Trust Unit Trading Statistics *($)*					
High	18.20	18.33	17.50	16.21	**18.33**
Low	14.75	14.73	14.21	10.60	**10.60**
Closing	17.45	16.30	15.30	12.57	**12.57**
Unit volume traded (thousands)	18,619	12,619	15,524	23,725	**279,051**
Exchangeable Shares Trading Statistics *($)*					
High	21.29	21.76	22.48	20.40	**22.48**
Low	18.49	18.28	18.60	14.90	**14.90**
Closing	20.70	19.57	18.60	16.21	**16.21**
Share volume traded (thousands)	85	15	69	31	**200**

[1] See discussion in the Management Discussion and Analysis

[2] Includes exchangeable shares converted at the end of period exchange ratio.

2006 SELECTED QUARTERLY INFORMATION

Operational Highlights	Three Months Ended 2006				Annual
	March 31	June 30	Sept. 30	Dec. 31	2006
Daily Production					
Natural gas (mcf/d)	86,433	82,271	85,701	88,568	**85,749**
Crude oil (bbls/d)	2,605	2,099	2,056	2,030	**2,196**
Natural gas liquids (bbls/d)	1,390	1,478	1,327	1,269	**1,366**
Total daily production (boe/d)	18,401	17,288	17,667	18,060	**17,853**
Average Realized Prices					
Natural gas - before hedging ($/mcf)	8.80	6.53	6.28	7.05	**7.17**
Natural gas - after hedging ($/mcf)	8.74	7.83	7.63	8.35	**8.14**
Crude oil ($/bbl)	64.45	72.79	75.69	59.26	**67.88**
Natural gas liquids ($/bbl)	62.86	63.34	68.29	55.71	**62.65**
Highlights ($/boe)					
Weighted average sales price	55.29	45.41	44.50	45.25	**47.65**
Realized gain (loss) on financial instruments	(0.37)	6.08	6.47	6.29	**4.60**
Royalties	(14.87)	(11.94)	(11.24)	(10.29)	**(12.09)**
Operating expenses	(5.81)	(6.15)	(6.18)	(6.63)	**(6.19)**
Transportation expenses	(1.91)	(1.68)	(1.61)	(1.56)	**(1.69)**
Operating Netbacks	32.33	31.72	31.94	33.06	**32.28**
General and administrative expense	(1.08)	(1.08)	(0.79)	(0.93)	**(0.97)**
Unit based compensation	(0.61)	(0.64)	(0.84)	(0.90)	**(0.75)**
Interest and financing expenses	(1.45)	(1.60)	(2.02)	(2.16)	**(1.81)**
Depletion, depreciation and accretion	(14.27)	(14.49)	(14.59)	(14.77)	**(14.53)**
Net earnings before taxes	14.92	13.91	13.70	14.30	**14.22**
Capital taxes	(0.20)	0.16	(0.03)	(0.03)	**(0.03)**
Future income taxes recovery/(expense)	0.56	6.98	0.83	0.85	**2.25**
Non-controlling interest – exchangeable shares	(2.37)	(2.98)	(2.04)	(2.16)	**(2.38)**
Net Earnings	12.91	18.07	12.46	12.96	**14.06**
Drilling Results					
Gross	39	15	22	30	**106**
Net – natural gas	19.3	11.0	9.8	15.6	**55.7**
Net – crude oil	0.8	0.4	1.6	2.0	**4.7**
Success Rate (percent)	93	100	95	100	**97**

CORPORATE INFORMATION

DIRECTORS

David D. Johnson
Chairman
Progress Energy Ltd.
President & CEO
ProEx Energy Ltd.
Calgary, Alberta

Donald F. Archibald [(1)(4)(5)]
Chairman & CEO
Cyries Energy Inc.
Calgary, Alberta

John A. Brussa [(3)(5)]
Partner
Burnet, Duckworth and Palmer LLP
Calgary, Alberta

Frederic C. Coles [(1)(2)(4)(5)]
Independent Businessman
Calgary, Alberta

Howard Crone [(1)(2)(4)(5)]
Independent Businessman
Calgary, Alberta

Michael R. Culbert
President and CEO
Progress Energy Ltd.
Calgary, Alberta

Gary E. Perron [(1)(3)(5)]
Senior Vice President and
Managing Director
BMO Nesbitt Burns
Calgary, Alberta

(1) Member of Audit Committee
(2) Member of Reserve Committee
(3) Member of Compensation Committee
(4) Member of Technical Services Committee
(5) Member of Corporate Governance and Nominating Committee

Environment, Health and Safety matters are addressed by the entire Board of Directors

OFFICERS

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Senior Vice President, Exploration

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Vice President, Finance &
Chief Financial Officer

Gary A. Miller
Vice President, Operations

Cindy R. Rutherford
Vice President, Land

Neil H. Samis
Vice President, Production
(retiring March 31, 2008)

James L. Stannard
Vice President, Engineering

Gary R. Bugeaud
Secretary

CORPORATE OFFICE

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TRUSTEE AND TRANSFER AGENT

Computershare Trust Company
of Canada
Calgary, Alberta

STOCK EXCHANGE

The Toronto Stock Exchange trading symbols:
Trust Units - PGX.UN
Exchangeable Shares – PGE
6.75% Debentures – PGX.DB
6.25% Debentures – PGX.DB.A

SOLICITOR

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITOR

KPMG LLP
Calgary, Alberta

CONSULTING ENGINEERS

GLJ Petroleum Consultants
Calgary, Alberta

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Progress Energy Trust

2007 Annual Report

Progress

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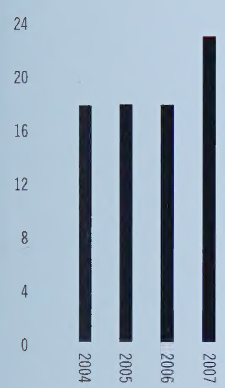
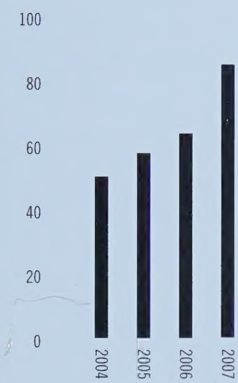
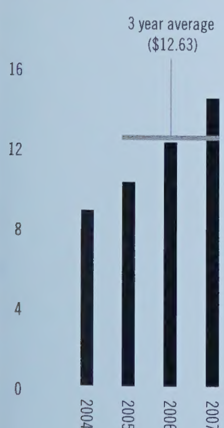
Production
(mboe/day)



Reserves
proved plus probable
(mmboe)



Drillbit Finding and Development Costs
($ per boe, proved plus probable)



Reserve Life Index
(years, proved plus probable)

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Vice President, Engineering

Gary R. Bugeaud
Secretary

TRUSTEE & TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta

STOCK EXCHANGE

The Toronto Stock Exchange
Trading Symbols:
Trust Units – PGX.UN
Exchangeable Shares – PGE
Convertible Debentures – PGX.DB
Convertible Debentures – PGX.DB.A

SOLICITOR

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